

DIRECT TESTIMONY OF
JOSEPH M. LYNCH
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2018-2-E

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Joseph M. Lynch and my business address is 220 Operation
3 Way, Cayce, South Carolina.

4
5 **Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

6 A. I am employed by SCANA Services, Inc. as Manager of Resource Planning.
7

8 **Q. PLEASE DESCRIBE YOUR DUTIES RELATED TO RESOURCE**
9 **PLANNING IN YOUR CURRENT POSITION.**

10 A. I am responsible for managing the department that produces South Carolina
11 Electric & Gas Company's ("SCE&G" or "Company") forecast of energy, peak
12 demand, and revenue. I also am responsible for developing the Company's
13 generation expansion plans and overseeing the Company's load research program.

1 **Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND**
2 **PROFESSIONAL EXPERIENCE.**

3 A. I graduated from St. Francis College in Brooklyn, New York, with a Bachelor
4 of Science degree in mathematics. From the University of South Carolina, I
5 received a Master of Arts degree in mathematics, an MBA, and a Ph.D. in
6 management science and finance. I was employed by SCE&G as Senior Budget
7 Analyst in 1977 to develop econometric models to forecast sales and revenue. In
8 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I
9 became Supervisor of Regulatory Research where I was responsible for load
10 research and electric rate design. In 1989, I became Supervisor of Forecasting and
11 Regulatory Research, and in 1991, I was promoted to my current position of
12 Manager of Resource Planning.

13
14 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE**
15 **COMMISSION OF SOUTH CAROLINA (“COMMISSION”)?**

16 A. Yes. I have testified on a number of occasions before this Commission.
17

18 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

19 A. The purpose of my testimony is to discuss SCE&G’s avoided costs for power
20 purchases under the Public Utilities Regulatory Policies Act of 1978 (“PURPA”).
21 The short-run avoided costs for qualifying facilities (“QFs”) that have power
22 production capacity less than or equal to 100 kilowatts (“kW”) are set forth in Rate

Schedule PR-1 attached to Witness Rooks' testimony as Exhibit Nos. __ (AWR-13) and __ (AWR-14). The long-run avoided costs for solar QFs that have production capacity greater than 100 kW and less than or equal to 80 megawatts ("MW") are set forth in Rate Schedule PR-2 attached to the Direct Testimony of Company Witness Allen Rooks as Exhibit Nos. __ (AWR-15) and __ (AWR-16). I also discuss the 11 components contained in the net energy metering ("NEM") methodology approved by the Commission in Order No. 2015-194 issued in Docket No. 2014-246-E.

AVOIDED COSTS UNDER PURPA

Q. WHAT DOES PURPA REQUIRE?

A. PURPA and its implementing regulations require electric utilities, including SCE&G, to purchase electric energy from qualifying small power production facilities and QFs at the utilities' avoided costs. However, state public utility commissions, such as the Commission, determine the method for calculating avoided costs.

Q. WHAT ARE AVOIDED COSTS?

A. PURPA regulations define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). The Federal Energy

1 Regulatory Commission (“FERC”) further recognizes that avoided costs include
2 two components: “energy” and “capacity.” Specifically, “[e]nergy costs are the
3 variable costs associated with the production of electric energy (kilowatt-hours).
4 They represent the cost of fuel, and some operating and maintenance expenses.
5 Capacity costs are the costs associated with providing the capability to deliver
6 energy; they consist primarily of the capital costs of facilities.” *Small Power
7 Production and Cogeneration Facilities; Regulations Implementing Section 210 of
8 the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg.
9 12,214, 12,216 (Feb. 25, 1980) (“Order No. 69”). In Order No. 81-214 and
10 subsequent decisions, the Commission has recognized that utilities are entitled to
11 recover their avoided costs under PURPA.
12

13 **Q. WHAT APPROACH DOES SCE&G TAKE TO CALCULATE THE**
14 **ENERGY AND CAPACITY COMPONENTS OF AVOIDED COSTS?**

15 A. As approved by the Commission in Order No. 2016-297, SCE&G uses a
16 difference in revenue requirements methodology to calculate both the energy
17 component and the capacity component of its avoided costs. This approach follows
18 directly from PURPA’s definition of avoided costs in that it involves calculating the
19 revenue requirements between a base case and a change case. The base case is
20 defined by SCE&G’s existing fleet of generators and the hourly load profile to be
21 supplied by these generators. The change case is the same as the base case except
22 that the hourly loads are reduced by a 100 MW profile, which is the maximum

1 reduction required by PURPA regulation 18 C.F.R. § 292.302(b)(1) for utilities with
2 systems larger than 1,000 MW of generation such as SCE&G. Using a carefully
3 constructed computer program called PROSYM, which models the commitment
4 and dispatch of generating units to serve load hour-by-hour, SCE&G estimates the
5 production costs that result from serving the base case load. A change case is derived
6 from the base case by subtracting an appropriate 100 MW power purchase profile.
7 Then, as with the base case, PROSYM is used to estimate the production costs that
8 result from serving the change case. The avoided energy cost is simply the
9 difference between the base case costs and the change case costs. The avoided
10 capacity cost is the difference between the incremental capacity costs in both its
11 base resource plan and the change plan.

12
13 **Q. WHAT PERIOD OF TIME DOES THE COMPANY USE TO CALCULATE**
14 **ITS AVOIDED COSTS?**

15 A. The short-run avoided energy costs are calculated for the period May 2018
16 through April 2019. The long-run avoided costs are calculated for calendar years
17 2018 through 2032, which is the time period appropriate for SCE&G's 2018 15-
18 year Integrated Resource Plan ("IRP") planning horizon pursuant to S.C. Code Ann.
19 § 58-37-40. These 15-years are divided into three groups of five years each: 2018-
20 2022, 2023-2027, and 2028-2032.

Q. WHAT IS SCE&G'S CURRENT RESOURCE PLAN?

A. SCE&G's current resource plan is attached as Exhibit No. __ (JML-1).

Q. WHAT IS SCE&G'S CURRENT RESERVE MARGIN POLICY USED IN DEVELOPING THIS RESOURCE PLAN?

A. Table 1 below summarizes SCE&G's reserve margin policy.

Table 1
Minimum Reserve Margin as Percent of Seasonal Peak Demand

	SUMMER	WINTER
Base Level	12%	14%
Peaking Level	14%	21%
Increment for Peaking	2%	7%

SCE&G has determined that during the months of May through October, which are grouped as "SUMMER", it needs resource reserves of at least 14% of the projected summer peak demand to serve reliably during peak times and at least 12% during the remaining periods. Likewise, for the months of November through April grouped as "WINTER", SCE&G needs a minimum of 21% of its projected winter peak demand to serve reliably during winter peak periods and at least 14% during the remaining periods. More details can be found in SCE&G's Reserve Margin Study which is attached as Exhibit No. __ (JML-2).

1 **Q. WILL SCE&G FILE THIS RESOURCE PLAN WITH THE COMMISSION**
2 **AS PART OF ITS 2018 IRP FILING?**

3 A. That is SCE&G's present intention. However, it is worth mentioning that the
4 resource plan is only a plan, and not necessarily a decision. SCE&G therefore
5 reserves the right to make changes as may be warranted or required by new or
6 changed circumstances.

7
8 **Q. IS SCE&G PROPOSING CHANGES TO ITS PR-1 AND PR-2 RATES?**

9 A. Yes. As I will further discuss in more detail below, SCE&G proposes to limit
10 the availability of its PR-2 Rate to solar QFs only and to offer separate rates for solar
11 and non-solar QFs in its PR-1 Rate. SCE&G also proposes to update PR-2 Rate
12 going forward only on an "as needed" basis instead of twice a year.

13
14 **PR-2 RATE**

15 **Q. WHY IS SCE&G PROPOSING TO LIMIT THE PR-2 RATE TO SOLAR**
16 **QFs?**

17 A. SCE&G must separate solar QFs from non-solar QFs in order to pay each
18 type of QF the correct avoided costs. As more and more solar generation facilities
19 interconnect with SCE&G's system, the benefit of each additional solar generation
20 facility to the Company's system is diminished. SCE&G performed a study titled
21 "Avoided Energy Cost Methods Study for Solar QFs" ("Methods Study") to
22 measure this effect and it is attached to this testimony as Exhibit No. __ (JML-3).

1 The Methods Study demonstrates that if SCE&G does not distinguish its pricing
2 between solar and non-solar QFs, then the amount SCE&G and its customers would
3 be paying for solar energy would be more than the Company's actual avoided costs,
4 which is contrary to the explicit intent of PURPA.

5
6 **Q. WHAT SPECIFICALLY IS THE DIFFERENCE BETWEEN SCE&G'S**
7 **TRADITIONAL ROUND-THE-CLOCK METHODOLOGY AND ITS**
8 **SOLAR METHODOLOGY?**

9 A. The avoided costs in the PR-2 rate are calculated over the 15-year IRP
10 planning horizon and the avoided energy costs are divided into 3 five-year periods
11 with the energy costs levelized within each period. As mentioned previously,
12 SCE&G's avoided costs are calculated based on the difference in revenue
13 requirements between a base case and a change case over this 15-year period.

14 Under the traditional methodology, the change case is derived from the base
15 case by subtracting a 100 MW round-the-clock profile from the base case, i.e., 100
16 MWs are subtracted from every hour of the base case load profile. Avoided energy
17 costs are then collected into four time periods composed of two seasons—peak
18 season and off-peak season—and two daily periods—peak hours and off-peak
19 hours. The peak season includes the months of June, July, August, and September.
20 The peak hours during the peak season are 10:00 a.m. through 10:00 p.m. The peak
21 hours for the off-peak season are 6:00 a.m. through 10:00 a.m. and 5:00 p.m. through
22 10:00 p.m. except during the months of May and October when they revert to the

1 peak hours defined for the peak season. Using these four time-of-use periods results
2 in four avoided energy costs, one for each time period.

3 Under the solar methodology, the change case is derived from the base case
4 by subtracting a 100 MW solar profile from the base case. Because the solar
5 distribution of energy is captured in the solar profile, avoided energy costs are not
6 collected into separate time periods but simply added over all hours.

7
8 **Q. HOW WAS THE METHODS STUDY STRUCTURED?**

9 A. The Methods Study compared the traditional round-the-clock methodology
10 and the solar methodology using the PROSYM model to estimate the difference in
11 revenue requirements between the base case and three different change cases. The
12 first change case used the round-the-clock 100 MW purchase. The second change
13 case was derived using a power purchase from a 100 MW South Carolina solar
14 profile. The third change case used a North Carolina solar profile to help determine
15 the impact on avoided costs based on a different solar profile. Because PROSYM
16 simulates random plant forced outages, the estimate of avoided energy costs could
17 change simply by assuming a different set of forced outages. Therefore, for each
18 case, the Company ran PROSYM 10 times, each time using a different random
19 number seed to simulate a different set of plant forced outages, thus generating a
20 slightly different avoided energy cost in each run. SCE&G then averaged the results
21 of the 10 runs to determine the difference in revenue requirements.

Q. WHAT WERE THE CONCLUSIONS OF THE METHODS STUDY?

A. For each PROSYM simulation and for each year in the IRP planning period, SCE&G calculated the avoided energy costs, which are documented in the appendix to the Methods Study. The avoided energy costs were then levelized using present worth arithmetic and averaged over the 10 random seed runs. Table 2 below summarizes the calculations of the avoided energy costs under the round-the-clock profile case, which are also reflected on page 3 of the Methods Study.

Table 2
Avoided Energy Costs for Round-the-Clock Methodology

	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off- Peak Hours
Avoided Costs (\$/MWH)	\$36.27	\$32.57	\$35.82	\$34.44
SC Solar Weights (kWh/kW)	470	287	672	682
Resulting Weighted-Average Avoided Cost Using SC Solar Weights				\$35.03

Avoided Costs (\$/MWH)	\$36.27	\$32.57	\$35.82	\$34.44
NC Solar Weights (kWh/kW)	496	299	580	612
Resulting Weighted-Average Avoided Cost Using NC Solar Weights				\$35.02

Table 3 below compares the avoided costs of a solar generator using the round-the-clock 100 MW purchase methodology shown in Table 2 above with the avoided costs of a solar generator using the solar profile 100 MW purchase methodology, as also reflected on page 3 of the Methods Study.

Table 3
Avoided Cost Results Levelized

\$/MWH	Round-the-Clock 100 MW Purchase	Solar Profile 100 MW Purchase	Difference
SC	\$35.03	\$30.18	\$4.85
NC	\$35.02	\$30.86	\$4.16

The results show that using the round-the-clock profile to develop the change case results in over-estimating the avoided energy costs by \$4.85 per MWH. The avoided costs calculated based on the North Carolina profile are consistent with those of the South Carolina profile and therefore support these findings.

Q. WHY DOES ADDING SOLAR ENERGY TO THE SYSTEM RESULT IN REDUCING AVOIDED ENERGY COSTS BY \$4.85 PER MWH?

A. As more and more solar is added to the system, the value of each additional increment of solar is reduced. One of the reasons for this diminishing value can be demonstrated by the so-called solar “Duck Curve.” As shown in the graph on page 2 of the Methods Study, the Company’s residual system load profile for many days of the year begins to reflect the silhouette of a duck as more solar is added to the system. Specifically, SCE&G’s system first experiences a morning peak demand with little contribution from solar facilities. As the day progresses and solar facilities begin generating energy, SCE&G’s residual system load profile experiences a steep ramping down of load to a bottom level of load followed by a steep ramping up in load to an afternoon or evening peak demand. In sum, the additional energy from

1 solar generation causes the system to experience decreasing minimum loads
2 between the morning and evening peak.

3 This curve creates operational problems in running the system as system
4 operators have to select resources that can follow the load both down the curve and
5 up the curve. Operational problems also occur under low load conditions because
6 each generating unit has a minimum operating level below which it cannot be
7 operated. If a baseload unit is taken off-line to prevent the system from over-
8 generating during the low load conditions, then its capacity must be replaced during
9 the ramping up period in order to serve the afternoon/evening peak. Additionally,
10 some of the units that continue to operate to serve the low load must operate at an
11 output level that is less efficient, i.e., more costly, than the optimum output level for
12 which they were designed. Thus, while solar energy coming onto the system
13 certainly has value, it also causes operational issues that result in positive variable
14 integration costs that lower the avoided cost.

15
16 **Q. IS SCE&G ABLE TO CAPTURE ALL THE VARIABLE INTEGRATION**
17 **COSTS ASSOCIATED WITH THE OPERATIONAL ISSUES CAUSED BY**
18 **THE INCREASED SOLAR ON THE SYSTEM?**

19 A. No. The \$4.85 per MWH lower avoided energy cost is calculated based on
20 the expected commitment and dispatch of generating units needed to serve
21 forecasted load hour-by-hour. Although this reduction reflects part of the variable
22 energy costs associated with the addition of large amounts of solar to the system, it

certainly does not capture all of these costs. Under real world conditions faced by system operators, the availability and operation of generators, the need to commit some units as standby extra capacity, the weather and load for the next day, the effect of clouds on solar facilities, and other similar constraints will always result in operational conditions that differ in some degree from the forecasts and estimates used in calculating the avoided energy costs. This uncertainty causes an increase in the Company's production costs.

Q. BASED ON THE COMPANY'S ANALYSIS, WHAT ARE SCE&G'S AVOIDED ENERGY COSTS FOR THE PR-2 RATE?

A. Table 4 below contains the avoided energy costs for the PR-2 rate.

Table 4
Solar QF Avoided Energy Costs (\$/kWh)

Time Period	Annual
2018-2022	\$0.02853
2023-2027	\$0.02994
2028-2032	\$0.03414

Q. HOW DOES SCE&G CALCULATE ITS AVOIDED CAPACITY COSTS RELATED TO SOLAR FACILITIES ON THE COMPANY'S PR-2 RATE?

A. SCE&G takes a similar approach to developing avoided capacity costs as it does with avoided energy costs. Using the difference in revenue requirements methodology approved by the Commission in Order No. 2016-297, SCE&G calculates the difference in the revenue requirement between the base case and the

1 change case. Using the resource plan in its latest IRP or an updated resource plan if
2 appropriate, SCE&G calculates the incremental capital investment related revenue
3 required to support the existing resource plan. As with its calculation of avoided
4 energy costs for solar, SCE&G derives a change case in its resource plan by
5 considering the impact of a QF purchase from a 100 MW solar facility.

6
7 **Q. USING THIS METHODOLOGY, WHAT ARE THE AVOIDED CAPACITY**
8 **COSTS FOR THE PR-2 RATE?**

9 A. SCE&G currently has over 700 MWs of solar capacity under Power Purchase
10 Agreements (“PPAs”) and the addition of another 100 MWs of solar has no effect
11 on the resource plan. Stated differently, given the amount of solar generation that is
12 currently projected to be interconnected to SCE&G’s system, adding additional
13 blocks of 100 MW of solar generation does not affect the Company’s future capacity
14 needs. For this reason, the avoided capacity costs of solar reflected in the PR-2 rate
15 is zero.

16
17 **Q. WHY DOESN’T ADDITIONAL SOLAR CAPACITY AFFECT SCE&G’S**
18 **FUTURE CAPACITY NEEDS?**

19 A. SCE&G performed a study that analyzed the impact of solar on its daily peak
20 demands. This study titled “On Calculating the Capacity Benefit of Solar QFs
21 (“Solar Capacity Benefit Study”), a copy of which is attached as Exhibit No. __
22 (JML-4), shows that, on more than 80% of the days during the winter months of

October through March, solar has no effect on SCE&G's daily peak demand. This is because the winter peak occurs either early in the morning before solar begins to generate energy or in the evening after solar is no longer generating. Table 5 below is an excerpt from the Solar Capacity Benefit Study. It shows the number of days by month that solar has no effect on the daily peak demand.

Table 5
Number of Days By Month When
Solar Has No Effect on the Peak Demand

Amount of Solar Capacity Added to the System (MWs)				
Month	200	500	800	1000
1	27	27	27	28
2	19	23	24	25
3	23	26	27	29
4	8	13	20	22
5	3	6	7	7
6	0	0	0	0
7	0	0	0	0
8	0	0	2	3
9	2	2	5	6
10	15	20	25	26
11	21	22	23	24
12	21	23	23	24
Total	139	162	183	194

Since SCE&G's Reserve Margin Study shows that SCE&G needs as much capacity in the winter as it does in the summer, a resource has to provide capacity in the winter as well as the summer in order to avoid the need for capacity and thereby have capacity value. Because solar does not provide capacity during the winter

1 period, the Company is unable to avoid any of its projected future capacity needs
2 and, therefore, the avoided capacity cost of solar for these winter months is zero.
3

4 **Q. TABLE 5 ALSO SHOWS THAT SOLAR IMPACTS THE DAILY PEAK ON**
5 **MOST DAYS IN THE SUMMER AND ON ALL OF THE DAYS IN JUNE**
6 **AND JULY. DID SCE&G ANALYZE THE IMPACT OF SOLAR ON THESE**
7 **SUMMER DAYS?**

8 A. Yes. This issue is also discussed in the Solar Capacity Benefit Study. Table
9 6 below, which is included on page 6 of the Solar Capacity Benefit Study, shows
10 the impact of seven different solar farms, scaled up to 800 MWs on the five days of
11 highest peak demand in the summer season. The farms are scaled to 800 MWs so
12 as to approximate the over 700 MWs of solar capacity currently under PPAs plus
13 the addition of another increment of 100 MWs whose impact is being reflected in
14 avoided costs.

Table 6
5 Highest Summer Peak Days with 800 MWs of Solar

Solar Farm	No. of Days	Peak Reduction (MWs)	% Reduction	Last 100 MWs
Farm 1	5	313.8	39.2	24.5
Farm 2	5	273.8	34.2	24.7
Farm 3	5	223.4	27.9	15.6
Farm 4	5	340	42.5	21.4
Farm 5	5	262.5	32.8	11
Farm 6	5	204.1	25.5	17.7
Farm 7	5	310.2	38.8	21.9
Average	5	275.4	34.4	19.5

On average over the 5 peak days, an 800 MW solar facility can be expected to reduce the daily peak demand by approximately 34.4% in the summer season, which equates to approximately 275 MWs. The last 100 MWs of the 800 MWs has an incremental effect of about 19.5%, which is approximately 19.5 MWs.

The following table shows similar results for the remainder of the summer season.

Table 7
Remaining Days of the Summer Season with 800 MWs of Solar

Solar Farm	No. of Days	Peak Reduction (MWs)	% Reduction	Last 100 MWs
Farm 1	148	153.6	19.2	8.7
Farm 2	179	152.1	19	10.4
Farm 3	122	167.7	21	8.2
Farm 4	163	176.5	22.1	10.4
Farm 5	163	188.5	23.6	9.7
Farm 6	179	174.5	21.8	9.9
Farm 7	179	162.1	20.3	10.1
Average	167.9	167.9	21.0	9.6

1 Thus, 800 MWs of solar can be expected to reduce the daily peak demand on
2 average over non-peak days approximately 21% with only 9.6% for the last 100
3 MWs. Because only the incremental values are relevant for avoided cost
4 calculations, the last 100 MWs of solar will reduce the summer peak by about 19.5
5 MWs on peak days and 9.6 MWs on the rest of the days. This translates into a peak
6 effect of approximately 9.9 MWs and a base effect of approximately 9.6 MWs.
7 Considering this small impact in summer and no impact in winter, SCE&G is not
8 able to reduce capacity additions in its resource plan and therefore there are no
9 avoided capacity costs.

10
11 **Q. WHY DOES SCE&G LIMIT ITS EVALUATION OF AVOIDED COSTS TO**
12 **THE 15-YEAR PLANNING HORIZON OF ITS IRP?**

13 A. It is important to recognize that future projections are uncertain. For avoided
14 energy costs, it is not clear whether the projected costs over the last 5 years of the
15 IRP planning horizon are too high or too low for those 5 years, let alone the 5 or 10
16 years beyond. Therefore, using projected costs beyond the 15-year planning horizon
17 would be unreasonably speculative and would increase the costs borne by SCE&G's
18 customers.

1 **Q. HOW WILL SCE&G ADDRESS AVOIDED COSTS FOR NON-SOLAR QFs**
2 **OF GREATER THAN 100 KW AND UP TO 80 MW?**

3 A. SCE&G plans to negotiate contracts with any non-solar QF for which the
4 PR-1 rate is not appropriate. In the past and prior to the development of the PR-2
5 rate, SCE&G for many years offered a PR-1 rate as well as an offer to negotiate a
6 contract with any QF that did not qualify for the PR-1 rate. This response to PURPA
7 worked satisfactorily for many years and SCE&G proposes to return to that
8 arrangement for non-solar QFs of greater than 100 kW and up to 80 MW.

9
10 **Q. WHY IS SCE&G ALSO PROPOSING TO UPDATE THE PR-2 RATE ONLY**
11 **ON AN “AS NEEDED” BASIS INSTEAD OF TWICE A YEAR?**

12 A. Avoided costs are based on projections of load, resource needs, fossil fuel
13 prices, etc., over the IRP planning horizon. If the avoided costs do not change
14 significantly, then there is no need for an update. Instead, SCE&G believes it is
15 more appropriate to update the PR-2 Rate only when there is a significant change in
16 the avoided cost projections, or more specifically, when the Company’s long run
17 avoided costs change significantly.

18
19 **PR-1 RATE**

20 **Q. WHAT MODIFICATIONS TO THE PR-1 RATE IS SCE&G PROPOSING?**

21 A. As discussed previously, SCE&G proposes to have separate rates for solar
22 QFs and non-solar QFs both with capacities up to and including 100 kW.

1 **Q. WHY IS SCE&G PROPOSING TO HAVE SEPARATE PR-1 RATES FOR**
2 **SOLAR QFs AND NON-SOLAR QFs?**

3 A. For the same reasons I discussed previously regarding the PR-2 rate, SCE&G
4 must separate solar QFs from non-solar QFs in order to pay each type of QF the
5 correct avoided costs. As reflected in the Methods Study, the benefit of each
6 additional solar generation facility to the Company's system is diminished as more
7 and more solar generation facilities interconnect with SCE&G's system. If SCE&G
8 does not distinguish its pricing between solar and non-solar QFs, then the amount
9 SCE&G and its customers would be paying for solar energy would be more than the
10 Company's actual avoided costs, which is contrary to the explicit intent of PURPA.

11
12 **Q. HOW DOES SCE&G COMPUTE THE AVOIDED ENERGY COMPONENT**
13 **FOR SOLAR QFs SUBJECT TO THE PR-1 RATE?**

14 A. SCE&G uses the same methodology to estimate avoided energy costs for
15 solar QFs on PR-1 as it did for solar QFs on PR-2. The only difference is the time
16 period over which the avoided energy costs are estimated. The short-run avoided
17 energy costs in the PR-1 rate are calculated for the period May 2018 through April
18 2019.

1 **Q. WHAT IS THE AVOIDED CAPACITY COST COMPONENT FOR SOLAR**
2 **QFs IN THE PR-1 RATE?**

3 A. The avoided capacity cost for solar QFs subject to the PR-1 rate is zero. As
4 explained with respect to the PR-2 rate, incremental solar QFs do not affect the
5 resource plan and therefore avoid no future resources or their cost.

6
7 **Q. HOW DOES SCE&G COMPUTE THE AVOIDED ENERGY COMPONENT**
8 **FOR NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?**

9 A. As discussed previously, SCE&G uses PROSYM to estimate the change in
10 production costs that result from serving the base case load and the change case.
11 The change case for non-solar QFs is derived from the base case by subtracting a
12 100 MW round-the-clock power purchase profile. The avoided costs are then
13 accumulated into the four time-of-use periods described above. A non-solar QF
14 would be paid based on how much energy it produces in each of these four time-of-
15 use periods.

1 **Q. HOW DOES SCE&G COMPUTE THE AVOIDED CAPACITY**
2 **COMPONENT FOR NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?**

3 A. Normally SCE&G would calculate its avoided capacity costs by taking the
4 difference in avoidable costs between a base resource plan and a change case.
5 However, because the PR-1 rate is designed for small QFs with a capacity rating of
6 up to 100 kW, SCE&G does not believe there will ever be enough capacity from
7 these small non-solar QFs to affect its resource plan and, therefore, the avoided
8 capacity costs for PR-1 are zero.

9
10 **Q. IS SCE&G PROPOSING OTHER CHANGES TO THE PR-1 RATE FOR**
11 **NON-SOLAR QFs?**

12 A. Yes. Previously, SCE&G defined two “critical peak hour” periods and used
13 the number of hours in these periods to convert the annual capacity cost from \$ per
14 kW-year into \$ per kWh. SCE&G proposes to eliminate the critical peak hours as a
15 way to credit QFs for their capacity value for several reasons. First, these critical
16 peak hours were established to accommodate solar facilities. Since SCE&G must
17 use a solar profile to calculate solar related avoided costs, it is more appropriate to
18 simply add an avoided capacity credit to the avoided energy cost to deliver the
19 capacity value to a solar QF. Second, the addition of so much solar on SCE&G’s
20 system shifts the Company’s previously experienced effective peak hour—the hour
21 that the residual load (system load minus solar generation) peaks. This can be
22 readily seen in the graph on page 2 in Exhibit JML-4. Because of this solar effect,

1 it is inappropriate to look only to certain hours selected from past experience in
2 which to pay out a capacity credit. Finally, as reflected in the Reserve Margin Study
3 and in Table 1 above, SCE&G has determined that, during the months of May
4 through October (“SUMMER”), the Company needs resource reserves of at least
5 14% of the projected summer peak demand during peak times, and at least 12%
6 during the remaining periods to reliably serve its customers. For the months of
7 November through April (“WINTER”), SCE&G needs a minimum of 21% of its
8 projected winter peak demand during peak times and at least 14% to serve the load
9 during the remaining periods. Since SCE&G’s need for capacity spans the entire
10 year, it is necessary to spread avoided capacity costs throughout the year to reflect
11 the Company’s reliability risk as explained in the Reserve Margin Study.

12
13 **Q. WHAT ADJUSTMENTS ARE MADE TO THE AVOIDED COSTS IN THE**
14 **PR-1 RATE?**

15 A. The avoided energy cost results for both solar QFs and non-solar QFs are
16 adjusted for line losses, working capital impacts, gross receipts taxes, and
17 generation taxes. The Company made no adjustments to the avoided capacity costs
18 for both solar and non-solar QFs under PR-1 because these costs are zero.

19
20 **Q. WHAT IS THE RESULTING PR-1 RATE?**

21 A. The avoided energy costs are shown in Table 8 below.

Table 8

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs (\$/kWh)

Time Period	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
May-April	\$0.03233	\$0.02886	\$0.03445	\$0.03298

Solar QFs (\$/kWh)

Time Period	Year Round
May-April	\$0.03256

The avoided capacity costs for solar and non-solar QFs are zero.

COMPONENTS OF VALUE FOR
NEM DISTRIBUTED ENERGY RESOURCES

Q. WHAT ARE THE COMPONENTS OF VALUE FOR NEM DISTRIBUTED ENERGY RESOURCES?

A. By way of its Order No. 2015-194 issued in Docket No. 2014-246-E, the Commission approved the following 11 components of value for NEM Distributed Energy Resources:

Net Energy Metering Methodology

1. +/- Avoided Energy
2. +/-Energy Losses/Line Losses
3. +/- Avoided Capacity
4. +/- Ancillary Services
5. +/- T&D Capacity
6. +/- Avoided Criteria Pollutants
7. +/- Avoided CO₂ Emission Cost
8. +/- Fuel Hedge
9. +/-Utility Integration & Interconnection Costs
10. +/- Utility Administration Costs
11. +/- Environmental Costs

= Total Value of NEM Distributed Energy Resources

In Docket No. 2017-2-E, the Company calculated the value for these components and, in Order No. 2017-246, the Commission determined that those values complied with the NEM Methodology approved by the Commission in Order No. 2015-194. Table 9 below shows the components of value of NEM Distributed Energy Resources approved by the Commission in Order No. 2017-246.

Table 9
Total Value of NEM Distributed Energy Resources (\$/kWh)
Approved in Order No. 2017-246

	Current Period	IRP Planning Horizon (15- Year Levelized)	Components
1	\$0.03273	\$0.03199	Avoided Energy Costs
2	\$0	\$0.00172	Avoided Capacity Costs
3	\$0	\$0	Ancillary Services
4	\$0	\$0	T & D Capacity
5	\$0.00004	\$0.00004	Avoided Criteria Pollutants
6	\$0	\$0	Avoided CO ₂ Emission Cost
7	\$0	\$0	Fuel Hedge
8	\$0	\$0	Utility Integration & Interconnection Costs
9	\$0	\$0	Utility Administration Costs
10	\$0	\$0	Environmental Costs
11	\$0.03277	\$0.03375	Subtotal
12	\$0.00268	\$0.00276	Line Losses @ 0.9245
13	\$0.03545	\$0.03651	Total Value of NEM Distributed Energy Resources

Q. HAS SCE&G UPDATED THESE COMPONENTS OF VALUE?

A. Yes. Table 10 shows the updated components of value for NEM Distributed Energy Resources. Two columns of numbers are shown: one for the current value and one for the value over the IRP planning horizon. The difference between these two columns of numbers represents the future benefits of DER and are subject to recovery under S.C. Code Ann. § 58-40-20(F)(6).

Table 10
Total Value of NEM Distributed Energy Resources (\$/kWh)

	Current Period	IRP Planning Horizon (15- Year Levelized)	Components
1	\$0.03074	\$0.03014	Avoided Energy Costs
2	\$0	\$0	Avoided Capacity Costs
3	\$0	\$0	Ancillary Services
4	\$0	\$0	T & D Capacity
5	0.00004	\$0.00004	Avoided Criteria Pollutants
6	\$0	\$0	Avoided CO ₂ Emission Cost
7	\$0	\$0	Fuel Hedge
8	\$0	\$0	Utility Integration & Interconnection Costs
9	\$0	\$0	Utility Administration Costs
10	\$0	\$0	Environmental Costs
11	\$0.03078	\$0.03018	Subtotal
12	\$0.00251	\$0.00246	Line Losses @ 0.9245
13	\$0.03329	\$0.03264	Total Value of NEM Distributed Energy Resources

Q. PLEASE EXPLAIN THE COMPONENTS OF VALUE FOR AVOIDED ENERGY COSTS AND AVOIDED CAPACITY COSTS SHOWN ON LINE NOS. 1 AND 2 OF TABLE 10.

A. The components of value for avoided energy costs and avoided capacity costs are based on the PURPA avoided cost values previously discussed with one adjustment. The avoided energy costs are adjusted to remove the cost of criteria pollutants, which is then reflected in the component shown on Line 5, Avoided Criteria Pollutants.

1 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ANCILLARY**
2 **SERVICES SHOWN ON LINE NO. 3 OF TABLE 10.**

3 A. Ancillary services refer to the need to balance the load and generation on the
4 system and include operating reserves, both spinning and non-spinning; frequency
5 regulation; and voltage control. SCE&G expects that the cost of providing these
6 ancillary services will increase with the addition of large amounts of solar energy.
7 Currently, however, at the relatively small amount of NEM Distributed Energy
8 Resources generation, SCE&G has again assigned a value of zero to ancillary
9 services as it did in Docket No. 2016-2-E.
10

11 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR TRANSMISSION**
12 **AND DISTRIBUTION CAPACITY SHOWN ON LINE NO. 4 OF TABLE 10.**

13 A. SCE&G's NEM distributed resources do not avoid transmission or
14 distribution capacity and therefore the value of this component is zero. On
15 SCE&G's transmission system, customer-scale NEM resources are distributed
16 across SCE&G's transmission system and have too small of an impact on any
17 transmission circuit to result in avoided transmission capacity. For example, the
18 most impacted substation currently on SCE&G's system is connected to 1,368 kW
19 of solar capacity owned by 178 customers. The impact of a 1,368 kW change in load
20 is much too small to affect the planning of or need for a 115 kV or a 230 kV circuit,
21 which carry loads between 237,000 and 948,000 kW.

1 On the distribution system, SCE&G's engineers must design a circuit for
2 circumstances that will stress the circuit. In particular, since solar output is
3 intermittent during the day and non-existent at night, they must also plan for when
4 the DER is not supplying power. The distribution line must carry the load both when
5 the DER is generating and when it is not because of weather related factors or
6 because DER resources are off line.

7
8 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR AVOIDED**
9 **CRITERIA POLLUTANTS SHOWN ON LINE NO. 5 OF TABLE 10.**

10 A. SCE&G associates a positive avoided cost value to criteria pollutants such
11 as NO_x and SO₂. The avoided cost of these pollutants typically is included in the
12 Company's avoided energy costs but, as I mentioned previously, these costs have
13 been separated out in this proceeding for reporting purposes.

14
15 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR AVOIDED CO₂**
16 **POLLUTANTS SHOWN ON LINE NO. 6 OF TABLE 10.**

17 A. Pursuant to Commission Order No. 2015-194, the component of value for
18 avoided CO₂ is set at zero until state or federal laws or regulations result in an
19 avoidable cost on utility systems for these emissions. Currently, there are no state
20 or federal laws or regulations restricting the emission of CO₂ pollutants and,
21 therefore, the value for CO₂ pollutants is zero.

1 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR FUEL HEDGE**
2 **SHOWN ON LINE NO. 7 OF TABLE 10.**

3 A. SCE&G does not hedge fuels for electric generation. Therefore, the value for
4 fuel hedging is zero.

5
6 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR UTILITY**
7 **INTEGRATION & INTERCONNECTION COSTS SHOWN ON LINE NO. 8**
8 **OF TABLE 10.**

9 A. At present, the integration and interconnection costs of NEM Distributed
10 Energy Resources are being collected through a DER rider added to the fuel clause.
11 Therefore, the value of this component is zero.

12
13 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR UTILITY**
14 **ADMINISTRATION COSTS SHOWN ON LINE NO. 9 OF TABLE 10.**

15 A. At present, the administration costs of NEM Distributed Energy Resources
16 are being collected through a DER rider being added to the fuel clause. Therefore,
17 the value of this component is zero.

18
19 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR**
20 **ENVIRONMENTAL COSTS SHOWN ON LINE NO. 10 OF TABLE 10.**

21 A. The component of "Environmental Costs" refers to any appropriate
22 environmentally related costs that were not already included in other net metering

1 methodology components. At present, there are no environmental costs that are not
2 already included in the other specific components of the methodology. Therefore,
3 the value of this component is zero.

4
5 **Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ENERGY**
6 **LOSSES/LINE LOSSES SHOWN ON LINE NO. 11 OF TABLE 10.**

7 A. When a NEM Distributed Energy Resource serves a customer's load behind
8 their meter or when it puts power onto the distribution system, SCE&G avoids
9 having to generate that specific amount of energy. The Company also avoids the
10 energy required to bring the power to the customer's meter or the distribution
11 system, i.e. the line losses associated with delivering power across the system. The
12 loss factor used for these NEM values represents the cumulative marginal line losses
13 at a residential customer's meter.

14
15 **CONCLUSION**

16 **Q. WHAT IS SCE&G REQUESTING OF THE COMMISSION IN THIS**
17 **PROCEEDING?**

18 A. SCE&G respectfully requests that the Commission 1) approve the
19 Company's proposed PR-1 and PR-2 Rates; 2) approve the total value of NEM
20 Distributed Energy Resources; 3) approve the costs incurred by the Company in
21 providing DER programs during the Review Period as being reasonable and

1 prudent; and 4) find that the Company's fuel purchasing practices were reasonable
2 and prudent for the Review Period.
3

4 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

5 A. Yes.

Exhibit No. __ (JML-1)

SCE&G Forecast of Summer Loads and Resources - 2018 IRP																															
			(MW)																												
	YEAR	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
Load Forecast																															
1	Baseline Trend	5103	5056	5148	5126	5239	5195	5333	5287	5459	5351	5559	5415	5652	5478	5738	5544	5820	5611	5900	5677	5976	5743	6049	5805	6116	5869	6186	5934	6254	5998
2	EE/Renewables Impact	-26	-32	-37	-55	-59	-78	-80	-101	-100	-123	-119	-158	-151	-179	-169	-197	-184	-220	-205	-245	-226	-270	-248	-295	-269	-317	-287	-340	-306	-361
3	Gross Territorial Peak	5077	5024	5111	5071	5180	5117	5253	5186	5359	5228	5440	5257	5501	5299	5569	5347	5636	5391	5695	5432	5750	5473	5801	5510	5847	5552	5899	5594	5948	5637
System Capacity																															
4	Existing	5278	5464	5782	5883	5697	5858	5672	5858	5672	5858	5672	5858	6212	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6182	6398	6275	6491
5	Existing Solar	58.73	0	96.36	0	161.6	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0	302.8	0
6	Demand Response	274	222	275	223	276	324	277	325	278	326	280	327	281	328	282	329	283	330	285	331	286	332	287	333	288	333	290	334	291	335
	Additions:																														
7	Solar Plant	37.63	0	65.21	0	141.2	0																								
8	Peaking/Intermediate																												93		
9	Baseload		504										540	-30																	
10	Retirements			-85		-25																									
11	Total System Capacity	5648	6190	6134	6106	6251	6182	6252	6183	6253	6184	6255	6725	6766	6726	6767	6727	6768	6728	6770	6729	6771	6730	6772	6731	6773	6731	6775	6825	6869	6826
12	Firm Annual Purchase	300			50		25		100		150																				
13	Total Production Capability	5948	6190	6134	6156	6251	6207	6252	6283	6253	6334	6255	6725	6766	6726	6767	6727	6768	6728	6770	6729	6771	6730	6772	6731	6773	6731	6775	6825	6869	6826
Reserves																															
14	Margin (L13-L3)	871.4	1166	1023	1085	1071	1090	998.8	1097	893.8	1106	814.8	1468	1265	1427	1198	1380	1132	1337	1075	1297	1021	1257	970.8	1221	925.8	1179	875.8	1231	920.8	1189
15	% Reserve Margin (L14/L3)	17.2%	23.2%	20.0%	21.4%	20.7%	21.3%	19.0%	21.2%	16.7%	21.2%	15.0%	27.9%	23.0%	26.9%	21.5%	25.8%	20.1%	24.8%	18.9%	23.9%	17.8%	23.0%	16.7%	22.2%	15.8%	21.2%	14.8%	22.0%	15.5%	21.1%

2017 Reserve Margin Study



Summary**Introduction**

All electric utilities require supply reserves to mitigate the risk of not being able to serve their load requirement because of demand-side related risk and supply-side related risk. Demand-side risk results from uncertainty in the level of demand which can increase because of abnormal weather or other unforeseen circumstances. Supply-side risk results from the possibility of supply resources either not being available at all or their capacity being reduced because of mechanical, fuel, weather or other circumstances. SCE&G is also required to carry operating reserves sufficient to meet its VACAR reserve sharing agreement. While SCE&G's share of the VACAR reserves can change each year, it is typically within a few megawatts of 200 MWs which is the amount SCE&G uses in its planning.

Reserve Margin Components	
1.	VACAR Operating Reserves
2.	Demand-Side Risk
3.	Supply-Side Risk

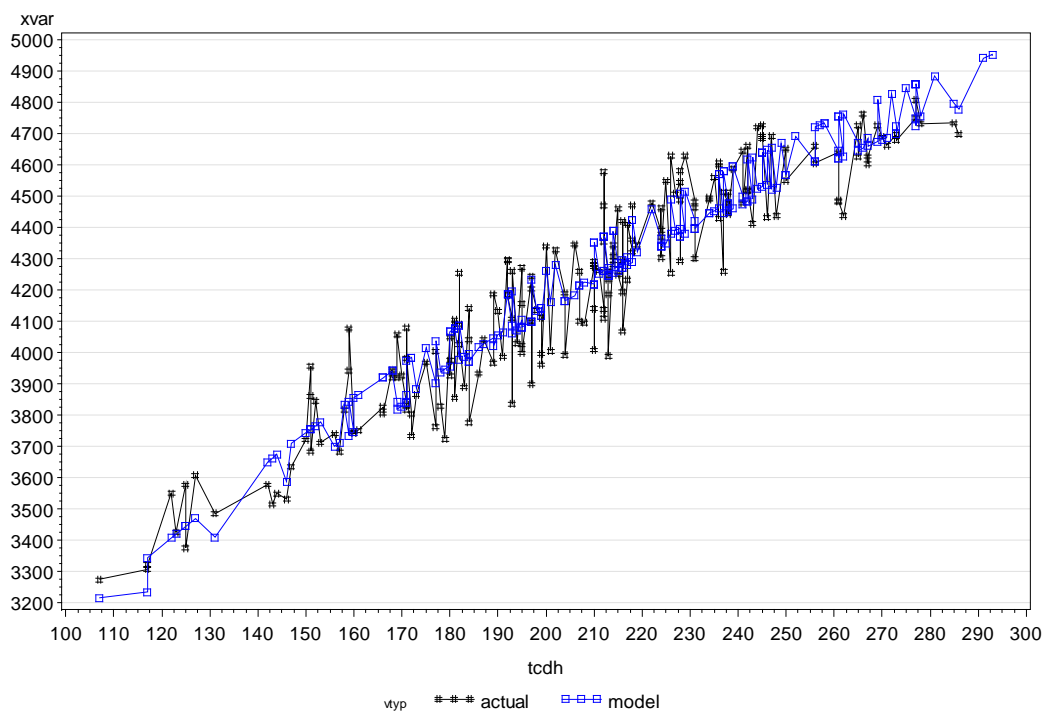
In determining its required reserve margin, SCE&G finds it necessary to analyze the need separately for the cooling season and the heating season. Additionally, within each season it is necessary to distinguish between a peaking need and a base need. There are at least two reasons for this dichotomy. First very cold weather can make SCE&G's winter peak spike for an hour or two. A peak clipping resource available for a few hours may be better suited to address this risk than a generating unit. Second, SCE&G anticipates a significant amount of solar capacity in its resource portfolio and the ability of solar to serve load can be substantially different during peak summer conditions as opposed to other times during the year.

Demand-Side Risk

The major source of demand-side risk derives from abnormal weather. To quantify the impact of weather on daily peak demands, two regression equations were estimated: one for summer relating daily summer peak demands to cooling degree hours and one for winter relating daily winter peak demands to heating degree hours. Three years of data were combined using the months of June, July and August for the summer model and December, January and February for the winter model. The following chart compares the summer regression model to the actual daily peak demands. The estimated regression equations and related statistics are included as appendices.

Peaks (3 Years) erc8d1.pgm

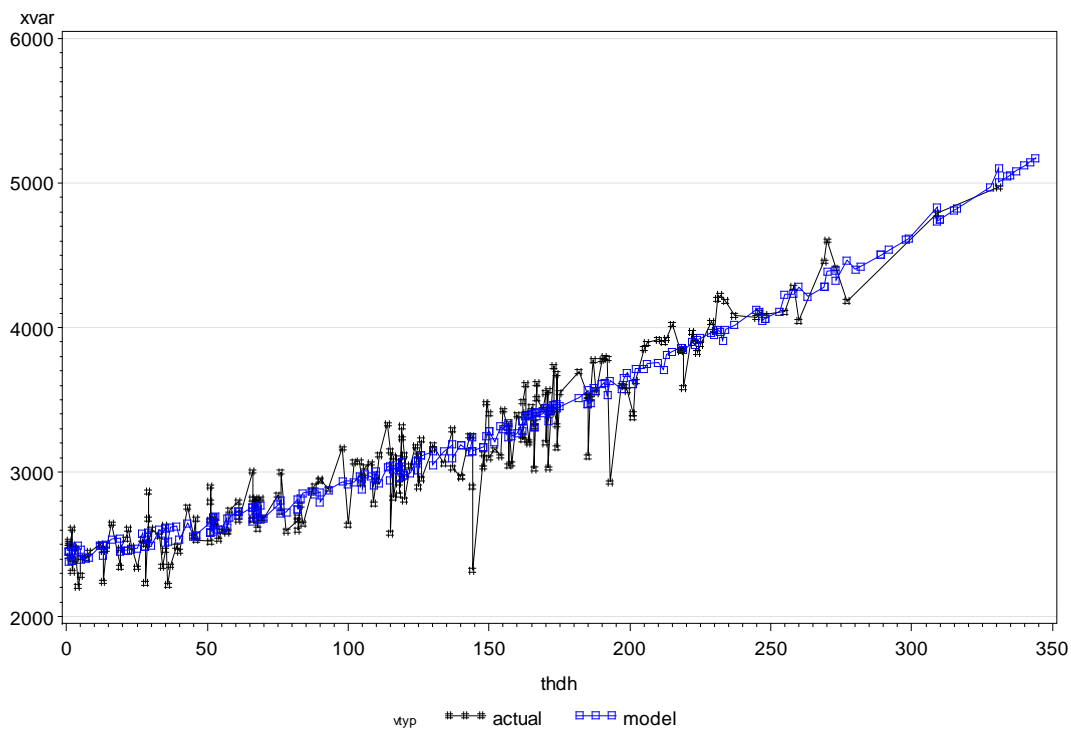
Weather Impact on Load



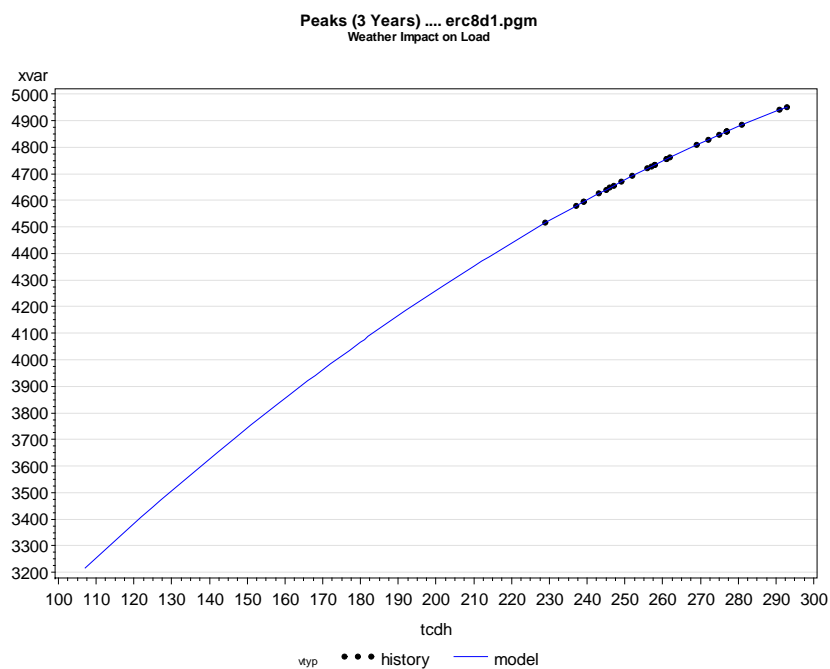
The following chart compares the winter regression model to the actual daily peak demands.

Peaks (3 Years) erc8d1.pgm

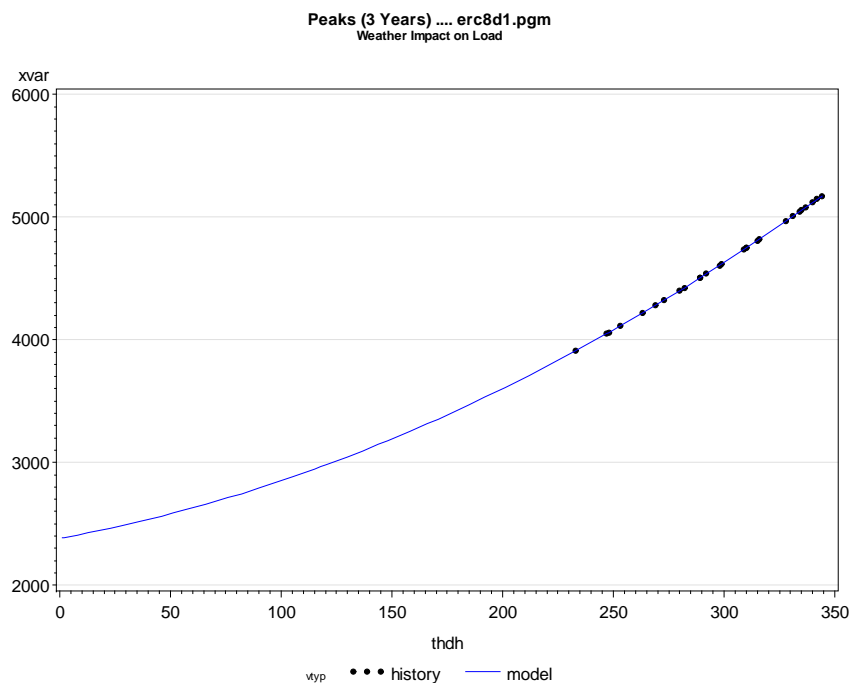
Weather Impact on Load



The next step was to use these regression equations to estimate what the peak demand would be on SCE&G's system today given the weather that occurred on historical peak days since 1991. The following chart displays the resulting summer peak demands and where they fall along the regression line.



The following is the similar graph for winter.

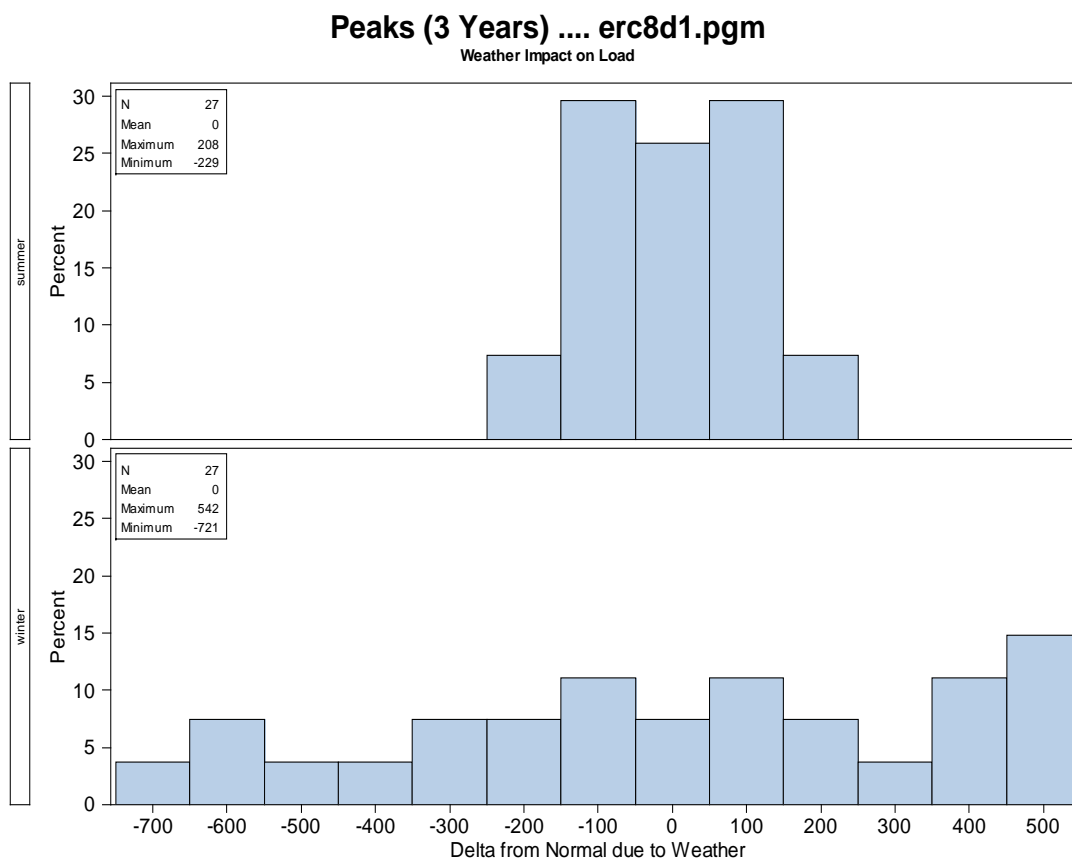


The following table shows the maximum peak demand that would result from the most extreme weather since 1991. The table also shows the average peak demand which represents the peak demand expected under normal or average weather conditions today. Finally, the table shows the maximum deviation from normal that could occur on SCE&G's system due to abnormal weather.

Table 1

MW Peak Demand				
Weather	Maximum	Normal	Deviation	%Deviation
Summer	4952	4744	208	4.4%
Winter	5172	4630	542	11.7%

By calculating the mean peak demand values and then taking deviations about that mean, a probability distribution of weather related deviations can be calculated for summer and winter. The following chart shows these probability distributions. The top distribution for the summer period is similar to a normal or bell-shaped probability distribution while the bottom chart representing the weather risk in winter is more spread out and similar to a uniform probability distribution.



The following table summarizes the risk of higher peak demands based on these distributions.

Table 2

MW Weather Deviations By Percentile				
Percentile	75%	90%	95%	100%
Summer	115	139	197	208
Winter	376	491	516	542

Clearly, winter weather poses a greater demand-side reliability risk than summer since the maximum deviation from a normal weather forecast can reach as much as 542 MWs while in summer the maximum deviation is closer to 208 MWs.

Supply-Side Risk

To quantify the supply-side risk, the forced outage history of SCE&G's generating units was analyzed. By calculating the number of MWs of generation that was forced out or de-rated on each day

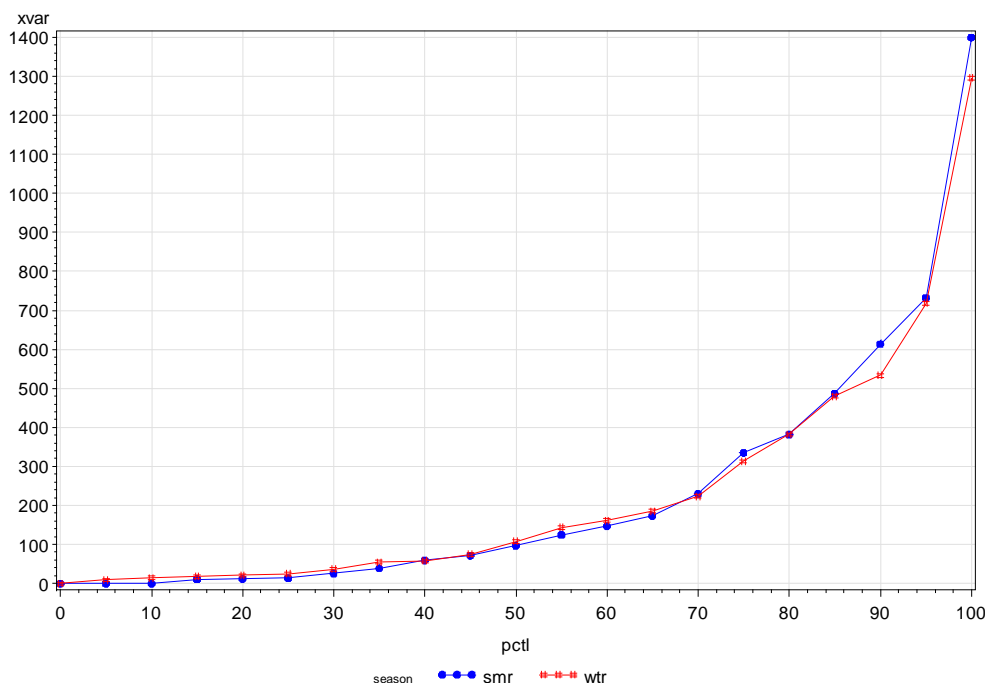
of the summer and winter, a distribution of outage was developed for the summer season and for the winter season. For summer, the daily outages during the months of June, July and August were studied for the years 2010-2016. For winter, the months of December, January and February were used. The resulting number of days used for summer was 644 and for winter 632. Below is a table summarizing each of these distributions.

Table 3

MWs Forced Out By Percentile						
Percentile	50%	60%	70%	80%	90%	100%
Summer	97	147	230	382	614	1400
Winter	108	162	224	382	534	1296

The following is the distribution in graphical form showing the accumulated MWs out by the percentile in the probability distribution.

Analyze Outage Data - Print Certain Days ... outage2b.pgm



To maintain reliability and replace the loss of generating capacity up to 70% of the days in summer, SCE&G estimates that it needs about 230 MWs of reserve capacity. For the winter season, 224 MWs of generating capacity is enough to back stand 70% of the days.

Summary: Reserve Capacity for Summer and Winter Peak Periods

To calculate the required reserve margins for summer and winter peak periods, SCE&G used the maximum deviation from normal estimated in the demand-side risk analysis and the 70% cutoff value from the outage distributions developed for the summer and winter seasons. The following table summarizes the results.

Table 4

Reserve Margin for Summer and Winter Peak Periods		
	Summer	Winter
VACAR Operating	200	200
Demand-Side Risk	208	542
Supply-Side Risk	230	224
Total Reserve MWs	638	966
Normal Peak Demand	4744	4630
Reserve Margin %	13.4%	20.9%
Reserve Margin Policy	14%	21%

SCE&G's reserve margin policy is to have a level of capacity reserves at least as great as 14% of the normal weather summer peak forecast for the summer season and 21% of the normal weather winter peak forecast for the winter season.

Reserve Capacity Needed to Operate the System Reliably Throughout the Year

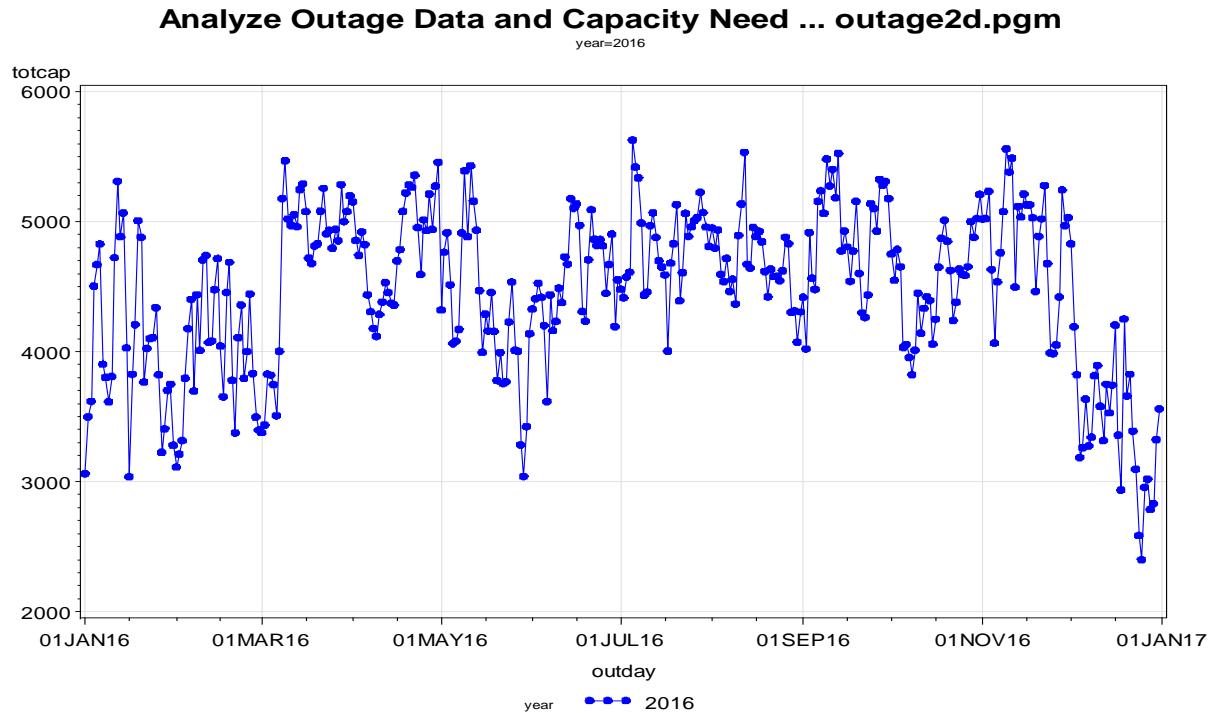
In addition to the reserves needed to address risk during the summer and winter peak periods, SCE&G also needs reserve capacity to operate the system throughout the year not only to meet the load but also cover both scheduled and un-scheduled generating unit outages. To quantify this need SCE&G analyzed its forced and scheduled outages since 2010 and determined the capacity needed each day throughout the year. The basic formula relating available capacity and system need is the following.

$$\text{Total Capacity} - \text{MWs Forced Out} - \text{MWs Scheduled Out} = \text{Peak Load} + \text{Residual Operating Reserves}$$

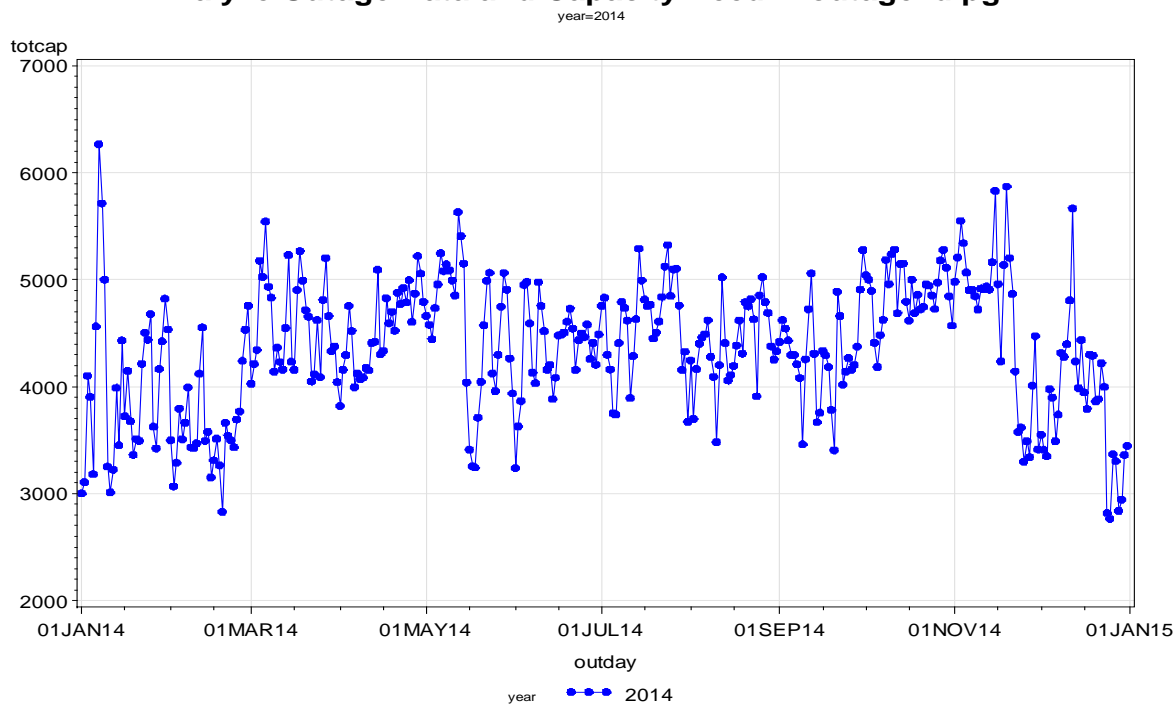
By rearranging terms, the daily capacity need can be calculated with this formula.

$$\text{Total Daily Capacity Needed} = \text{Daily Peak Load} + \text{MWs Forced Out} + \text{MWs Scheduled Out} + \text{Desired Daily Reserves}$$

Setting the “Desired Daily Reserves” equal to the VACAR Operating Reserve requirement of 200 MWs, SCE&G can calculate its daily capacity need by using its historical experience with scheduled and forced outages. Following is a graph of the daily capacity need in 2016.



Below is the chart for 2014 which was the year when an arctic blast of cold air hit the southeast on January 7, 2014. The spike in capacity needed above 6000 MWs was principally caused by the forced outage of Williams Station on that day.

Analyze Outage Data and Capacity Need ... outage2d.pgm

The daily capacity need for each year from 2010 to 2016 was calculated by season. Each year and season was considered a separate distribution of daily need and from each distribution the 95th, 96th and 97th percentiles were extracted. These percentiles represented the amount of capacity needed to serve 95%, 96% and 97% of the days in the distribution respectively. The peak days in the distribution, defined as the top 10 to 20 days of highest capacity need, correspond to a demarcation at the 95th and 97th percentile i.e. 10/365 is about 3% and 20/365 is about 5% of the days in the year or stated differently 355/365 is about 97% and 345/365 is about 95%. The individual years and seasons are shown in Appendix C. The table below shows the average of these percentiles from the seven years studied. For example, in the summer, SCE&G needs about 5,121 MWs of capacity to serve 95% of the days in the summer period while 5,312 MWs is needed to serve 97% of the days in the winter period. Since this level of capacity is needed to serve most of the days of the year, SCE&G considers this a base level of capacity.

Table 5

Distribution of Daily Capacity Need at Certain Percentiles (MWs)				
Percentile	95%	96%	97%	100%
Summer	5256	5306	5355	5705
Winter	5121	5184	5312	5731

In the following table, the base level of capacity is expressed as a percentage of the average maximum customer load occurring in the particular season. Averaging the percentages for the 95th and the 97th percentile yields 12.25% for summer and 14.05% for winter. SCE&G therefore establishes base reserve capacity need in summer of 12% of summer peak demand and in winter, 14% of winter peak demand.

Table 6

Daily Capacity Need Percentiles as Percent of Peak Load					
Percentile	95%	96%	97%	100%	Peak Load
Summer	11.2	12.2	13.3	20.7	4729
Winter	11.9	13.3	16.2	25.3	4600

Conclusion

For the summer months which include May through October, SCE&G requires base reserves in the amount of 12% of the summer peak load to operate the system reliably and 14% of summer peak load during the peak load periods. For the winter months of November through April, SCE&G requires 14% of the winter peak load forecast in base reserves to operate the system reliably and 21% for the peak load periods. The following table summarizes SCE&G's reserve margin policy.

Table 7

SCE&G's Reserve Margin Policy		
	Summer	Winter
Base Reserves	12%	14%
Peaking Reserves	14%	21%
Increment for Peaking	2%	7%

Appendix A: Regression Equation for Daily Summer Peak Demand against Cooling Degree Hours

Peaks (3 Years) erc8d1.pgm
Weather Impact on Load

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

Number of Observations Read	297
Number of Observations Used	270
Number of Observations with Missing Values	27

Weight: wghts Weight

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	29969188	4994865	443.08	<.0001
Error	263	2964842	11273		
Corrected Total	269	32934029			

Root MSE	106.17515	R-Square	0.9100
Dependent Mean	4139.00979	Adj R-Sq	0.9079
Coeff Var	2.56523		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > t	Variance Inflation
Intercept	1	4298.41935	14.09494	304.96	<.0001	0
ihol	1	-276.97847	62.00124	-4.47	<.0001	1.01145
wkend	1	-248.70374	14.53597	-17.11	<.0001	1.02044
cdh	1	9.17900	0.19527	47.01	<.0001	1.25657
cdh2	1	-2.06140	0.38020	-5.42	<.0001	1.01827
yr lag1	1	-134.68185	17.83707	-7.55	<.0001	1.66784
yr lag2	1	-109.94246	16.73247	-6.57	<.0001	1.47090

Appendix B: Regression Equation for Daily Winter Peak Demand against Heating Degree Hours

Peaks (3 Years) erc8d1.pgm
Weather Impact on Load

The REG Procedure
Model: MODEL1
Dependent Variable: mxload

Number of Observations Read	345
Number of Observations Used	318
Number of Observations with Missing Values	27

Weight: wgt5 Weight

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	93931187	15655198	790.70	<.0001
Error	311	6157566	19799		
Corrected Total	317	100088753			

Root MSE	140.70980	R-Square	0.9385
Dependent Mean	3002.63669	Adj R-Sq	0.9373
Coeff Var	4.68621		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > t	Variance Inflation
Intercept	1	2908.82737	16.76640	173.49	<.0001	0
ihol	1	-458.93137	46.27237	-9.92	<.0001	1.02568
wkend	1	-396.77172	17.77649	-22.32	<.0001	1.02971
hdh	1	6.35945	0.12564	50.62	<.0001	1.35070
hdh2	1	1.39994	0.14226	9.84	<.0001	1.28290
yr1ag1	1	67.80463	20.16022	3.36	0.0009	1.35901
yr1ag2	1	95.00406	19.81164	4.80	<.0001	1.40634

Appendix C: Daily Capacity Need by Year and Season for Certain Percentiles in the Distribution

Analyze Outage Data and Capacity Need ... outage2d.pgm

seas	wyear	ndys	mxcap	mxload	cap95	cap96	cap97	mxresm	mxresm 95	mxresm 96	mxresm 97
summer	2010.0	184.0	5778.0	4735.0	5268.0	5322.0	5415.0	22.0	11.3	12.4	14.4
	2011.0	184.0	5691.0	4885.0	5412.0	5462.0	5490.0	16.5	10.8	11.8	12.4
	2012.0	184.0	6179.5	4761.0	5222.5	5251.5	5297.5	29.8	9.7	10.3	11.3
	2013.0	184.0	5643.0	4574.0	5262.0	5304.0	5390.0	23.4	15.0	16.0	17.8
	2014.0	184.0	5632.5	4594.0	5187.0	5249.5	5280.0	22.6	12.9	14.3	14.9
	2015.0	184.0	5382.5	4750.0	5111.5	5163.5	5195.5	13.3	7.6	8.7	9.4
	2016.0	184.0	5628.5	4807.0	5326.0	5391.5	5419.5	17.1	10.8	12.2	12.7
summer		184.0	5705.0	4729.4	5255.6	5306.3	5355.4	20.7	11.2	12.2	13.3
=====		=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
winter	2010.0	181.0	5285.0	4718.0	5008.0	5049.0	5102.0	12.0	6.1	7.0	8.1
	2011.0	181.0	5638.5	4868.0	5014.0	5038.0	5130.0	15.8	3.0	3.5	5.4
	2012.0	182.0	5818.0	4397.0	5314.0	5377.0	5420.0	32.3	20.9	22.3	23.3
	2013.0	181.0	5944.0	3984.0	4914.0	5075.0	5376.0	49.2	23.3	27.4	34.9
	2014.0	181.0	6269.0	4853.0	5233.0	5344.0	5552.0	29.2	7.8	10.1	14.4
	2015.0	181.0	5598.0	4970.0	5081.0	5115.0	5246.5	12.6	2.2	2.9	5.6
	2016.0	182.0	5561.0	4409.0	5284.0	5291.0	5357.0	26.1	19.8	20.0	21.5
winter		181.3	5730.5	4599.9	5121.1	5184.1	5311.9	25.3	11.9	13.3	16.2
=====		=====	=====	=====	=====	=====	=====	=====	=====	=====	=====

Avoided Energy Cost Methods Study for Solar QFs

Summary: Because of the significant amount of solar QFs either currently generating on SCE&G's system or under a signed PPA to generate in the near future, SCE&G found it necessary to change how its avoided energy costs are calculated. This study shows that it is no longer feasible to use the traditional methodology of using a 100 MW power purchase in every hour of the year but instead that a 100 MW solar sourced power purchase should be used to calculate avoided energy costs.

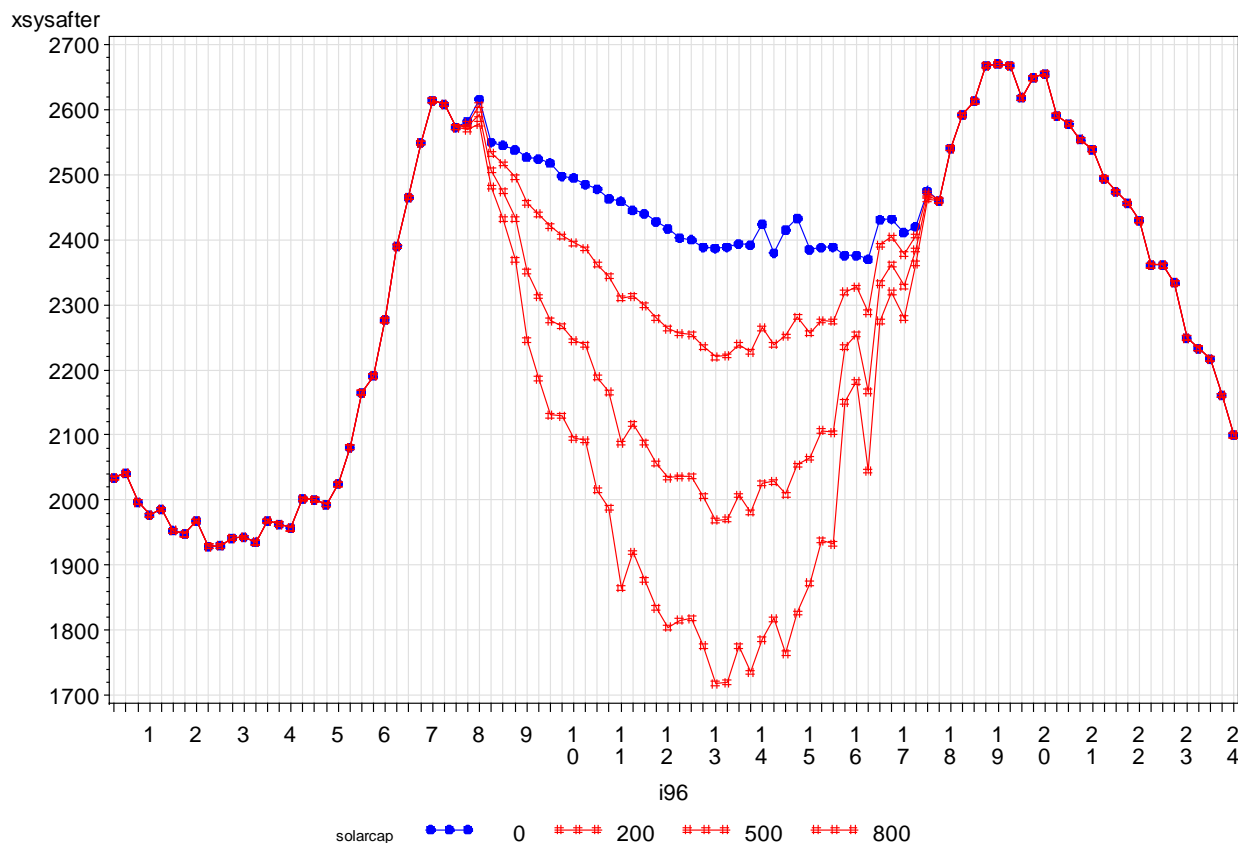
Introduction: SCE&G designed this study to measure the difference in estimated avoided costs when using its traditional methodology versus using a solar profile. Avoided energy costs are defined as those costs that would not be incurred, i.e., that can be avoided, by the purchase of energy from a QF. To calculate these avoided costs, SCE&G uses its PROSYM model to estimate the production costs of a base case and then a change case. In its traditional methodology, SCE&G created the change case by assuming a 100 MW round-the-clock purchase in every hour of the year and then collected the change in production costs into four time periods: 2 seasons X 2 daily periods. QFs would then be paid based on how much energy they generated in each period. For this study, SCE&G will also calculate the avoided costs that result when the 100 MW QF purchase follows the profile of a solar PV generator. Two solar profiles were chosen for the study to see how the results differ with the profile. Since the results of a PROSYM run can vary because of random plant outages, PROSYM was run 10 times in each case using a different random number seed and the averages of the results from these 10 runs were used as the basis of the comparison.

Operational Issues (The "Duck Curve"): As more and more solar QFs are added to the system, the graph of the changing system load begins to take the shape of a duck, thereby creating the moniker of the "Duck Curve". See the following graph. This graph can be used to demonstrate the increasing difficulty facing the rest of the generating fleet as more and more solar comes online. On this particular day January 19, 2017, the morning peak was over 2600 MWs and the evening peak a little higher, just under 2700 MWs. As more solar is added to the system, the belly of the duck grows and the system begins to face a lower and lower minimum load falling between the morning and evening peak. One problem this presents is called a "low load" problem where the load gets so low that some generators, perhaps a coal plant, must be taken off-line because it can't operate at an output below a certain minimum level. Even

if plants can remain operational at a lower level of output, the lower level will not be the most efficient operating point and the cost of their output will be higher than it would otherwise be. The other operational issue is the ramping rate. With more and more solar generation, the ramp rate down in the morning and the ramp rate up in the evening can be difficult to follow.

Analyze Daily System Peaks With Solar ... solar9e.pgm

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Fortunately, SCE&G has the Fairfield Pumped Storage unit which might alleviate some of the low load problem by pumping for a few hours. This unit is very flexible and can help with the ramping issue as well. Of course, while SCE&G may be able to serve the load under these conditions, the cost of serving the load will increase. This is the basic reason that SCE&G believes to accurately estimate its avoided costs for future solar QFs, it must now use a power purchase profile that is based on a solar generator.

The Results: The PROSYM model was run 40 times with each run simulating the system dispatch for a base case and a change case and calculating the difference in production costs over the 15-year planning horizon. In each case the avoided energy costs for the 15 years were levelized so a single number could be compared. The following table summarizes these results.

Table 1

Avoided Energy Cost Methods Study: Summary Results			
Seed	8760 Profile	SC Solar Profile	NC Solar Profile
1	35.41	31.26	30.48
2	34.45	30.46	29.53
3	34.87	29.83	30.32
4	34.84	30.01	32.10
5	35.01	30.19	31.24
6	35.36	32.31	30.49
7	34.78	29.43	30.56
8	35.03	28.62	32.08
9	35.91	31.67	30.44
10	34.67	27.98	31.33
Avg	35.03	30.18	30.86
Max	35.91	32.31	32.10
Min	34.45	27.98	29.53
Diff	1.46	4.33	2.57

The avoided energy cost based on the SC solar profile is \$30.18 per MWH while using the NC solar profile yields \$30.86 per MWH. The following table shows the calculation of avoided costs when using the traditional methodology to calculate avoided costs by time period and then pay the SC solar profile based on how much energy is generated in each period.

Table 2

	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
Avoided Costs (\$/MWH)	\$36.27	\$32.57	\$35.82	\$34.44
SC Solar Weights (kWh/kW)	470	287	672	682
Resulting Weighted-Average Avoided Cost Using SC Solar Weights				\$35.03

Avoided Costs (\$/MWH)	\$36.27	\$32.57	\$35.82	\$34.44
NC Solar Weights (kWh/kW)	496	299	580	612
Resulting Weighted-Average Avoided Cost Using NC Solar Weights				\$35.02

The difference in results for avoided energy costs using the SC solar weights is an indication of the additional production costs resulting from the operational issues caused by increased amounts of solar power on the system. Using the PROSYM model the estimated increase in cost is about \$4.85 per MWH (\$35.03 - \$30.18). Since the PROSYM model commits and dispatches units with 100% foreknowledge, this estimate must understate the true increase in operational costs.

Appendix

Results for Round-the-clock 8760 Profile**Random Seed 1**

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	30.57	25.16	35.41	34.78
2019	30.10	26.12	33.88	24.45
2020	29.65	31.17	37.00	31.54
2021	36.84	23.88	33.37	36.28
2022	33.50	31.24	34.72	33.71
2023	30.28	36.26	39.70	37.30
2024	32.08	33.98	28.46	32.77
2025	32.27	28.70	31.57	27.83
2026	32.77	29.76	32.80	32.37
2027	38.39	29.39	32.47	38.60
2028	38.49	29.91	36.18	33.70
2029	39.48	36.12	38.28	37.83
2030	46.00	36.57	40.97	38.93
2031	47.54	40.14	43.03	39.16
2032	48.62	42.91	47.31	41.74
Levelized	35.97	31.94	36.86	35.06

Random Seed 2

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	29.34	24.85	27.75	31.25
2019	27.93	27.19	27.20	30.17
2020	34.04	26.07	31.05	31.10
2021	39.64	28.67	30.87	32.46
2022	29.22	24.64	33.72	30.52
2023	34.08	30.59	34.90	39.76
2024	27.00	37.16	26.74	32.45
2025	38.09	29.10	33.94	31.13
2026	29.82	37.92	32.22	35.28
2027	31.72	33.73	34.67	35.91
2028	38.26	35.76	36.33	34.03
2029	38.68	36.53	37.73	34.80
2030	42.68	34.32	43.28	38.22
2031	49.58	40.17	46.40	37.87
2032	44.37	41.08	47.82	40.89
Levelized	35.42	32.11	34.44	34.78

Random Seed 3

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	28.79	25.44	29.56	29.06
2019	29.37	25.23	28.07	27.43
2020	26.34	29.93	29.21	28.45
2021	33.94	26.09	33.89	31.68
2022	40.22	30.60	31.86	31.44
2023	42.69	33.65	38.26	34.29
2024	34.79	31.76	34.96	29.46
2025	37.95	35.16	37.89	27.81
2026	39.11	36.39	34.52	37.33
2027	39.22	32.34	39.17	31.81
2028	41.09	30.99	32.45	37.84
2029	43.96	32.40	40.35	34.28
2030	38.55	36.96	44.10	39.31
2031	44.97	37.61	43.07	42.23
2032	45.08	39.79	42.02	39.15
Levelized	37.37	32.21	35.75	33.40

Random Seed 4

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	29.11	27.01	28.49	28.66
2019	33.26	28.77	33.06	31.21
2020	28.81	28.66	29.78	30.63
2021	31.61	31.73	32.50	30.39
2022	30.13	31.67	30.81	30.66
2023	41.01	30.74	37.49	38.76
2024	40.52	30.72	42.18	30.37
2025	29.99	33.08	34.35	32.13
2026	36.03	31.26	34.23	32.60
2027	42.63	31.37	30.70	33.57
2028	39.98	32.01	33.64	33.67
2029	37.74	33.47	35.69	37.57
2030	42.44	37.96	43.41	35.49
2031	49.11	34.35	39.85	38.81
2032	43.34	42.28	38.45	44.66
Levelized	36.70	32.53	35.27	34.11

Random Seed 5

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	29.64	28.56	35.23	32.30
2019	24.55	27.08	28.21	27.81
2020	29.12	31.68	28.23	28.93
2021	31.75	27.17	33.17	33.56
2022	31.61	30.54	35.97	34.21
2023	38.70	30.72	41.84	31.99
2024	30.71	30.29	30.43	26.19
2025	40.04	33.09	28.39	32.81
2026	42.05	33.85	36.57	34.29
2027	31.68	36.10	36.08	39.67
2028	38.46	36.99	37.36	32.51
2029	37.34	34.84	45.20	39.50
2030	41.89	38.12	42.83	35.71
2031	36.40	38.75	46.66	37.39
2032	54.30	38.67	43.70	41.92
Levelized	35.35	33.08	36.50	34.13

Random Seed 6

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	29.47	27.39	31.01	30.46
2019	31.03	26.40	37.74	27.87
2020	26.60	28.21	35.50	36.53
2021	31.25	30.07	25.95	33.84
2022	35.31	35.79	34.06	35.26
2023	33.41	31.66	33.61	33.15
2024	41.47	25.60	35.22	30.95
2025	25.29	34.05	35.06	28.47
2026	36.61	34.01	40.18	31.05
2027	36.35	33.71	41.27	35.35
2028	39.90	31.69	32.01	38.50
2029	47.37	32.33	42.61	37.27
2030	43.26	36.28	43.27	38.42
2031	42.94	38.15	37.98	37.57
2032	50.91	38.30	42.86	38.98
Levelized	36.09	32.40	36.80	34.69

Random Seed 7

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	27.98	25.70	30.96	29.25
2019	33.92	30.45	32.10	30.59
2020	29.32	30.64	29.71	28.42
2021	33.91	33.64	32.28	27.80
2022	37.47	26.64	33.17	31.81
2023	37.36	28.93	34.57	34.66
2024	27.51	35.27	33.98	36.21
2025	39.61	34.84	35.80	32.34
2026	39.13	31.20	35.46	38.68
2027	33.37	34.13	36.42	35.12
2028	39.67	34.35	26.73	36.02
2029	39.83	33.39	31.68	36.71
2030	37.60	38.98	36.81	36.32
2031	51.28	33.32	44.47	37.70
2032	48.31	39.93	42.47	38.22
Levelized	36.75	32.98	34.81	34.16

Random Seed 8

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	30.44	26.40	32.46	33.22
2019	27.76	28.00	37.48	27.42
2020	29.70	29.17	32.68	30.77
2021	32.13	27.26	30.85	28.94
2022	41.52	26.05	32.46	30.38
2023	35.03	34.77	33.35	30.76
2024	33.03	31.70	35.27	32.40
2025	29.07	31.58	39.93	28.45
2026	33.97	31.85	33.70	33.66
2027	37.57	32.90	38.79	38.70
2028	42.55	37.92	34.72	34.76
2029	40.66	35.16	41.63	38.69
2030	40.60	37.43	42.79	36.08
2031	47.30	36.53	36.40	39.20
2032	48.14	37.43	40.42	42.39
Levelized	36.20	32.24	36.66	33.80

Random Seed 9

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	31.01	26.38	32.74	34.19
2019	33.76	24.04	33.49	29.09
2020	31.08	34.47	34.30	31.00
2021	32.18	28.91	36.15	29.84
2022	38.35	29.65	35.18	34.07
2023	37.29	31.21	34.45	41.28
2024	34.39	29.58	32.28	33.37
2025	36.40	30.09	34.69	31.66
2026	43.88	29.51	34.29	36.33
2027	37.03	36.95	37.57	35.98
2028	34.56	37.52	34.81	35.27
2029	41.24	35.80	38.53	31.73
2030	43.60	35.19	41.09	38.50
2031	42.21	35.59	44.78	41.86
2032	44.64	39.21	42.54	42.32
Levelized	37.47	32.29	36.83	35.47

Random Seed 10

Year	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
2018	28.03	25.34	28.16	30.22
2019	27.74	28.66	30.93	28.67
2020	30.54	30.31	34.52	28.00
2021	37.30	31.68	28.45	29.01
2022	34.19	34.75	36.71	35.98
2023	35.78	35.42	36.05	38.65
2024	35.43	33.41	30.17	30.11
2025	34.54	31.62	25.48	32.86
2026	28.10	32.78	38.29	36.08
2027	40.55	34.17	38.28	36.56
2028	30.37	36.24	28.93	36.97
2029	38.44	41.58	37.14	36.59
2030	44.00	37.01	42.73	37.85
2031	46.04	37.78	33.92	44.08
2032	41.45	37.56	38.70	42.58
Levelized	35.38	33.95	34.30	34.84

SUMMARY TABLE

Leeds Profile	Peak Season Peak Hours	Peak Season Off-Peak Hours	Off-Peak Season Peak Hours	Off-Peak Season Off-Peak Hours
Seed1	35.97	31.94	36.86	35.06
Seed2	35.42	32.11	34.44	34.78
Seed3	37.37	32.21	35.75	33.40
Seed4	36.70	32.53	35.27	34.11
Seed5	35.35	33.08	36.50	34.13
Seed6	36.09	32.40	36.80	34.69
Seed7	36.75	32.98	34.81	34.16
Seed8	36.20	32.24	36.66	33.80
Seed9	37.47	32.29	36.83	35.47
Seed10	35.38	33.95	34.30	34.84
Average	36.27	32.57	35.82	34.44
Solar Weights	470	287	672	682
Levelized Avoided Solar Cost				35.03

Solar Weights	496	299	580	612
Levelized Avoided Solar Cost				35.02

RESULTS FOR TWO SOLAR PROFILE CASES

SC Solar Profile										
Year	Seed1	Seed2	Seed3	Seed4	Seed5	Seed6	Seed7	Seed8	Seed9	Seed10
2018	30.32	32.46	35.70	30.85	31.73	28.96	22.23	31.05	29.76	25.95
2019	33.18	30.31	23.18	28.04	30.53	32.59	32.42	27.08	29.04	26.92
2020	24.00	24.40	25.46	24.11	23.80	26.75	28.07	27.68	26.76	19.02
2021	27.74	24.28	29.66	27.03	27.94	28.11	24.82	25.49	25.48	27.85
2022	26.35	28.09	25.24	24.52	28.21	25.91	26.37	18.45	26.55	22.62
2023	28.31	31.90	24.87	32.56	26.64	34.32	27.06	19.08	38.74	24.40
2024	27.39	29.27	24.40	25.63	29.51	30.73	22.27	23.46	27.84	24.17
2025	30.70	25.17	27.50	29.85	22.18	27.49	29.75	28.04	31.45	26.12
2026	30.71	31.42	30.12	28.69	25.50	38.18	30.60	30.97	30.67	27.23
2027	34.79	30.89	24.35	28.95	33.43	35.11	31.27	30.29	33.15	31.18
2028	27.49	31.95	32.16	30.98	34.68	32.03	33.86	28.87	34.72	26.07
2029	36.73	30.78	33.97	27.09	29.97	39.09	31.00	29.03	31.22	34.70
2030	35.34	26.77	31.34	31.43	31.45	28.64	28.05	36.73	31.19	36.48
2031	31.06	38.70	35.60	35.55	28.27	32.22	35.52	33.98	33.85	31.53
2032	38.87	28.85	37.40	38.39	39.70	37.75	33.62	35.60	39.01	36.93
Levelized	31.26	30.46	29.83	30.01	30.19	32.31	29.43	28.62	31.67	27.98
			Average Levelized Avoided Cost Solar				30.18			

NC Solar Profile										
Year	Seed1	Seed2	Seed3	Seed4	Seed5	Seed6	Seed7	Seed8	Seed9	Seed10
2018	32.38	30.98	27.44	33.31	32.65	27.87	29.06	31.15	27.84	34.30
2019	34.11	32.26	25.56	32.87	26.74	34.48	27.63	30.69	27.70	23.78
2020	23.17	25.69	23.67	25.94	23.33	26.26	20.20	30.13	24.08	30.92
2021	13.41	22.42	27.92	29.43	26.10	23.26	29.74	27.10	24.08	28.49
2022	24.23	29.74	30.52	23.62	33.56	29.40	16.52	24.76	27.17	26.06
2023	25.91	23.07	29.34	31.28	30.60	31.17	30.05	27.91	27.23	28.05
2024	30.09	28.86	24.60	28.90	34.35	26.00	32.95	30.41	29.70	25.59
2025	29.99	25.56	30.66	27.76	22.65	19.56	31.67	29.39	33.72	30.17
2026	30.25	25.42	28.51	30.72	26.38	31.40	36.68	37.17	28.65	32.22

Exhibit No. __ (JML-3)

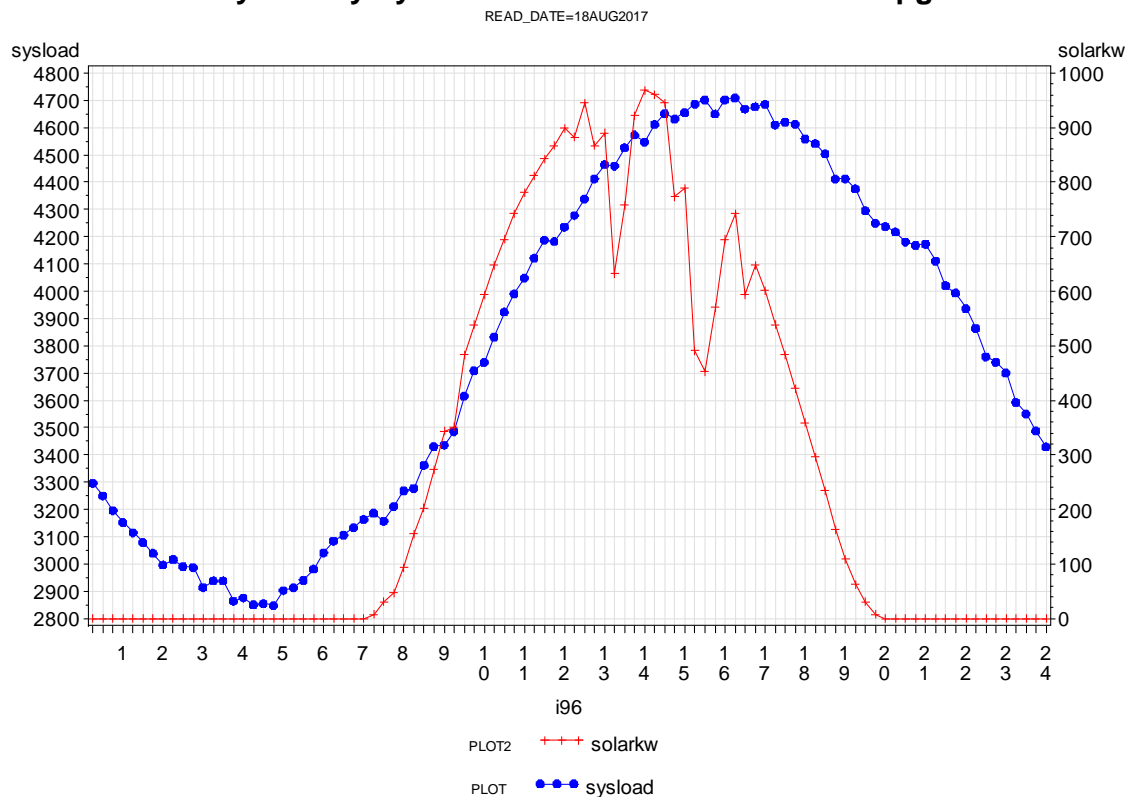
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2027	32.39	24.67	32.03	39.00	29.27	31.93	32.56	32.23	31.58	32.94
2028	38.05	29.46	29.67	32.51	34.14	30.78	33.41	34.31	32.82	29.06
2029	33.42	33.32	36.38	34.25	33.41	30.10	34.04	33.48	35.59	30.53
2030	39.32	34.44	37.39	33.33	37.22	35.20	35.54	33.66	37.44	37.85
2031	34.97	31.86	36.85	33.45	36.95	34.28	34.05	31.29	35.13	38.94
2032	35.82	35.53	34.05	36.20	36.79	39.75	35.54	42.01	33.89	35.11
Levelized	30.48	29.53	30.32	32.10	31.24	30.49	30.56	32.08	30.44	31.33
			Average Levelized Avoided Cost Solar				30.86			

On Calculating the Capacity Benefit of Solar QFs

Introduction: Before reporting detailed calculations, it is instructive to compare the daily profile of the system with a solar profile. The following chart compares the system and solar profiles on August 18th, the summer peak day of 2017. The system load is measured on the left vertical axis and the solar on the right. The solar profile comes from an actual solar farm on the SCE&G system but is scaled to a maximum capacity of 1,000 kW for illustration. One of the first points to notice is that, during this summer day, the solar profile is positive for about 13 hours, from 7:15 am (0715 hours) until about 8:00 pm (2000 hours). The system peak is about 4,700 MWs and by 8:00 pm (2000 hours) it decreases to about 4,300 when solar stops producing power. This means that no matter how much solar capacity is added to the system on this day the maximum effect will be to reduce the peak by 400 MWs. This is because the solar output will be zero at 8:00 pm (2000 hours) and therefore could not reduce the load below 4,300 MWs.

Analyze Daily System Peaks With Solar ... solar9e.pgm

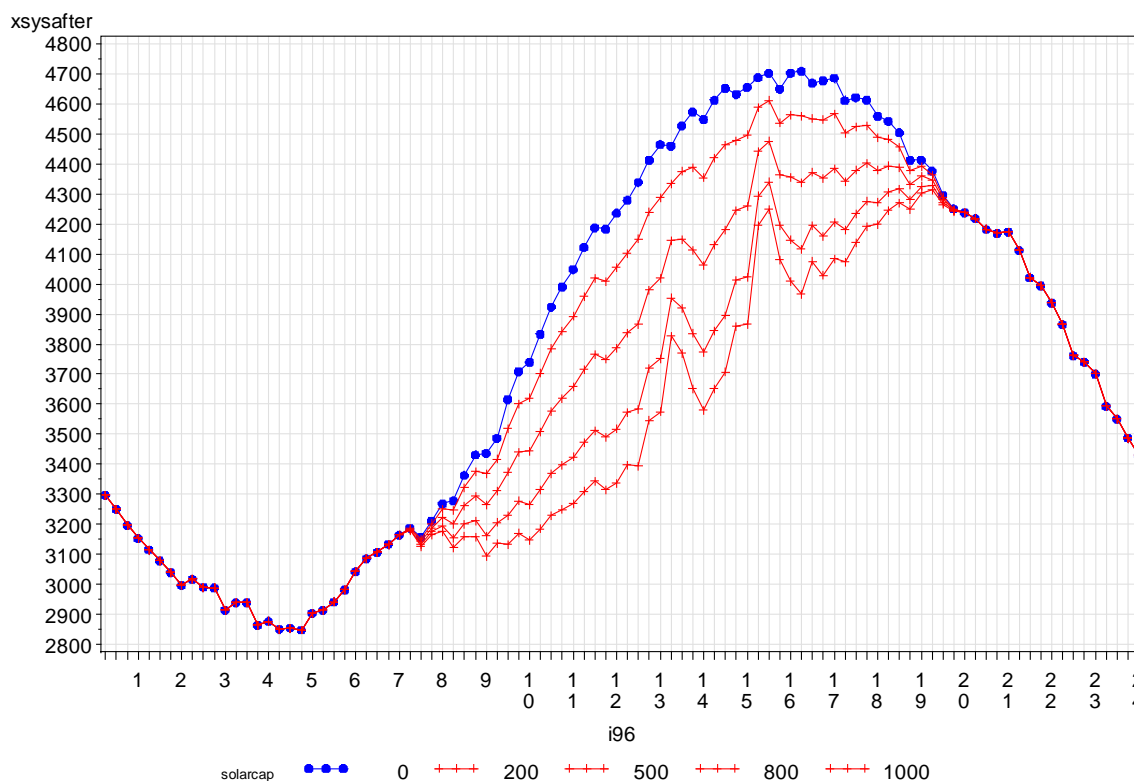


The following chart compares the system load without the addition of solar with the system load that results when 200, 500, 800 and 1000 MWs of solar capacity are subtracted from the original system load. Referring to the chart, the system load can be seen to be about 4700 MWs occurring about 3:30

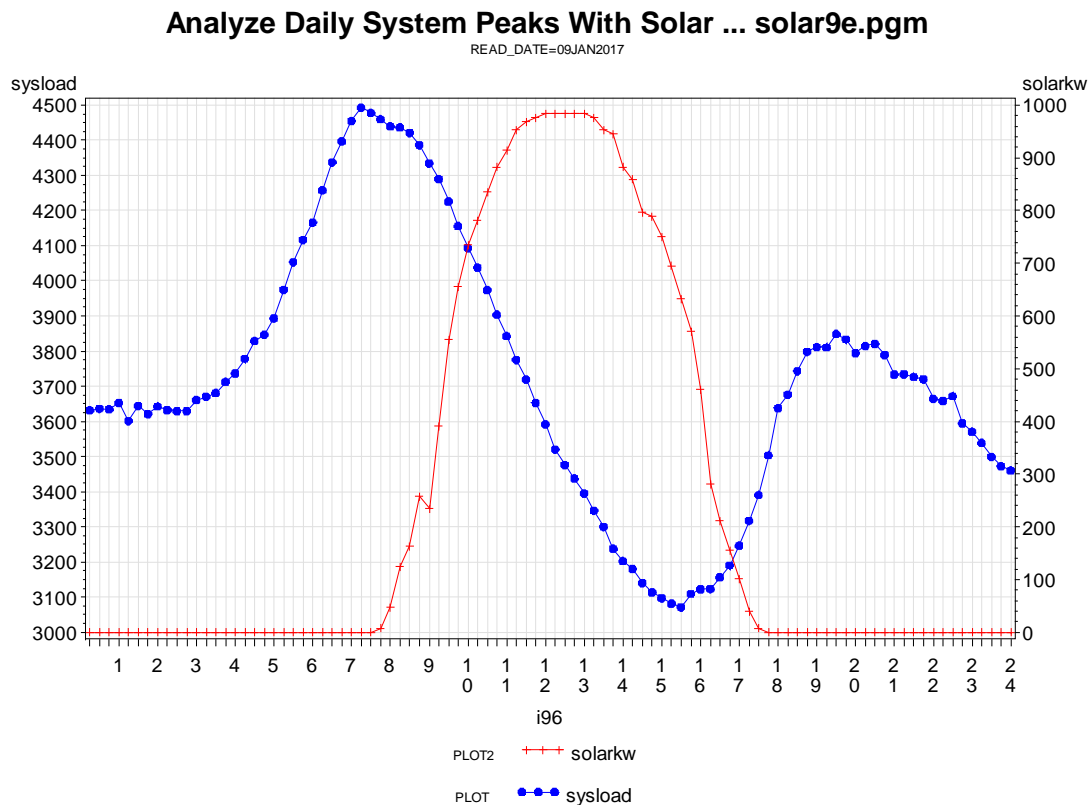
pm (1530 hours). When the effect of 200 MWs of solar is factored in, the load drops to about 4600 MWs at that same hour. When another 300 MWs of solar is added, the load drops another 125 MWs about at the same hour. However, with the addition of another 300 MWs making the solar total 800 MWs, the peak drops to about 4300 but the hour of the peak shifts to about 8:00 pm (2000 hours). At this point additional solar capacity will not affect the peak as can be seen when 200 MWs more is added making the total 1,000 MWs of solar. The peak remains at 4300 MWs at 8:00 pm (2000 hours).

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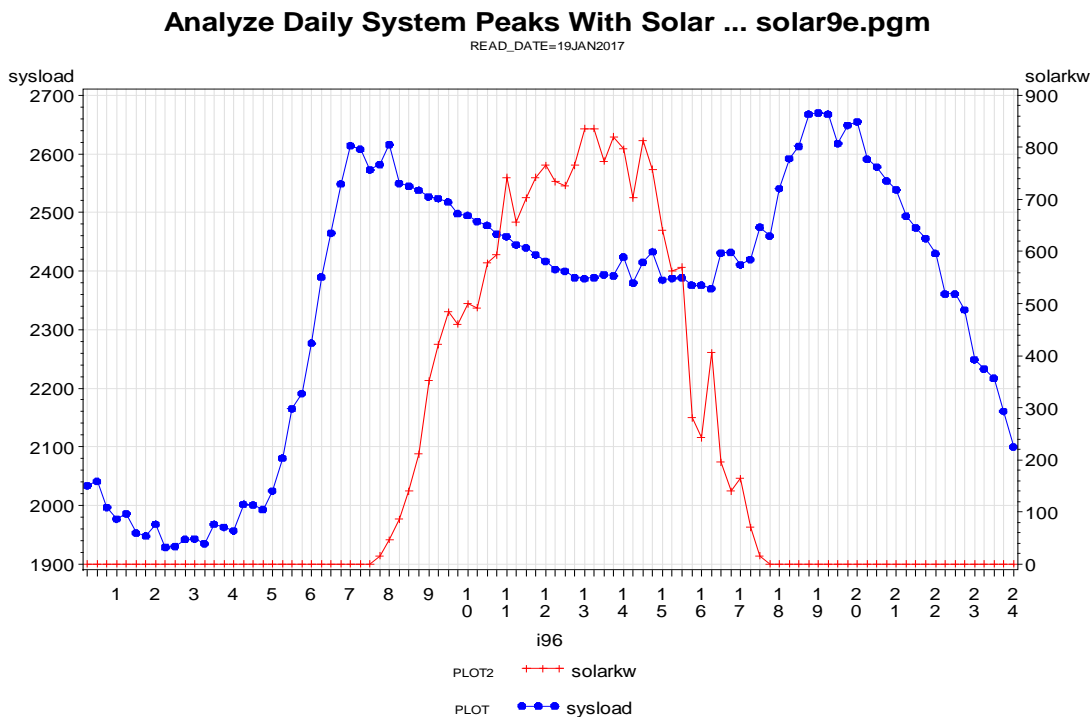
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A similar discussion can be made for a winter day. The following chart shows the system and solar profile for January 9th, the winter peak day of 2017. It is instructive to note that the solar profile is positive for about 10 hours from about 7:30 am (0730 hours) until about 5:30 pm (1730 hours). Since the system peaked at 7:15 am (0715 hours) on this day before solar generates power, no matter how much solar capacity is added to the system the peak demand of about 4500 MWs will not change. On this day, solar has no capacity value.



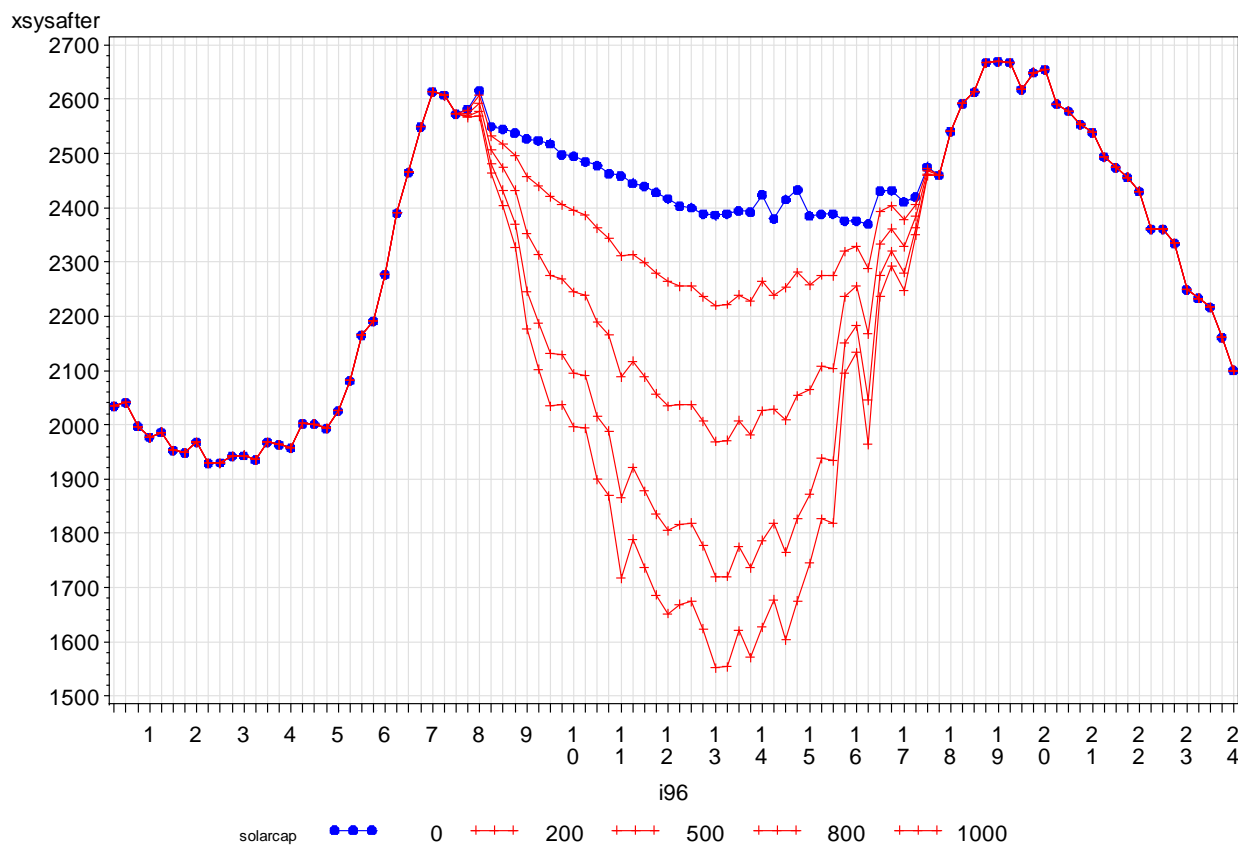
Many winter days are like this winter peak day in that the peak demand occurs either before or after the hours of solar output. The following chart contains similar information for January 19, 2017 when the system peaked just under 2700 MWs in the evening around 6:45 pm.



Below is the graph of the system load after adding 200, 500, 800 and then 1,000 MWs of solar capacity. The addition of solar certainly has a significant effect of the resulting load shape but notice that the peak demand is not affected.

Analyze Daily System Peaks With Solar ... solar9e.pgm

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Study Results: The previous charts and discussion are useful to understand what happens when solar capacity is added to the system but to have a complete picture it is necessary to look at all the days of the year. It has been shown that for at least two days the impact of solar on the need for capacity is zero. The following table shows the number of such days in the year by month for different levels of solar capacity. For example, if 800 MWs of solar are added to SCE&G's system in 2017, there would be 27 days in January on which the peak demand is not changed; 24 days in February, 27 in March, etc.

Table 1

Number of Days By Month When Solar Has Zero Impact on the Peak Demand										
	Amount of Solar Capacity Added to the System									
Month	100	200	300	400	500	600	700	800	900	1000
1	27	27	27	27	27	27	27	27	28	28
2	18	19	20	22	23	23	24	24	24	25
3	22	23	26	26	26	26	27	27	29	29
4	6	8	9	10	13	17	18	20	21	22
5	3	3	3	4	6	6	7	7	7	7
6	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	1	1	2	2	3
9	1	2	2	2	2	2	3	5	5	6
10	14	15	16	16	20	22	25	25	26	26
11	18	21	21	22	22	22	23	23	24	24
12	21	21	22	22	23	23	23	23	23	24
Total	130	139	146	151	162	169	178	183	189	194

It appears that for 7 months of the year, 800 MWs of solar will have no effect of the daily peak demand on most of the days of the month. For 5 months, however, i.e. for May through September, 800 MWs of solar will impact the peak demand on most days of the month and on all of the days in June and July.

Solar Impact in Winter: Consideration of the winter months October through March supports the conclusion that solar has zero capacity value in winter. There are 182 days in these 6 months and on 149 of those days, 800 MWs of solar capacity has no impact on the system peak demand reflecting an 82% fail ratio. It is useful to note the time of the system peak demand in the last 4 winter seasons. The table below contains this information.

Table 2

Winter Peak Days on SCE&G's System		
Day of Peak	Peak MWs	Time of Occurrence
January 07, 2014	4,717	7:30 am
February 20, 2015	5,035	7:00 am
January 19, 2016	4,451	7:00 am
January 09, 2017	4,493	7:15 am

Since all four peak demands occurred before 7:30 am, the presence of solar capacity would not have helped serve the peak load.

Solar Impact in Summer: The following tables show the results of the summer analysis. The first table shows the solar impact on the five highest peak days of the 2017 summer. For 800 MWs of solar added to the system, the average daily peak demand is reduced approximately 34.4% or about 275 MWs. The last 100 MWs of solar capacity, that is, the impact when solar capacity is increased from 700 MWs to 800 MWs, reduces the peak demand by 19.5 MWs on average which can also be expressed as 19.5%.

Table 3

5 Highest Summer Peak Days With 800 MWs of Solar				
Solar Farm	Nbr Days	Peak Reduction MWs	% Reduction	Last 100 MWs
Farm 1	5	313.8	39.2	24.5
Farm 2	5	273.8	34.2	24.7
Farm 3	5	223.4	27.9	15.6
Farm 4	5	340.0	42.5	21.4
Farm 5	5	262.5	32.8	11.0
Farm 6	5	204.1	25.5	17.7
Farm 7	5	310.2	38.8	21.9
Average			34.4	19.5

Analyzing the solar impact over the remaining days available in the summer season yields an average reduction in peak demand of 21.0% or 168 MWs. On an incremental basis, the impact of the last 100 MWs of solar is 9.6 MWs on average. The conclusion is that the last 100 MWs of capacity will provide about 9.6 MWs of system capacity relief for most of the summer season, i.e., during the months of May through October plus an additional 9.9 MWs on the summer peak day.

Table 4

Remaining Days of the Summer Season With 800 MWs of Solar				
Solar Farm	Nbr Days	Peak Reduction MWs	% Reduction	Last 100 MWs
Farm 1	148	153.6	19.2	8.7
Farm 2	179	152.1	19	10.4
Farm 3	122	167.7	21	8.2
Farm 4	163	176.5	22.1	10.4
Farm 5	163	188.5	23.6	9.7
Farm 6	179	174.5	21.8	9.9
Farm 7	179	162.1	20.3	10.1
Average			21.0	9.6